AE.2.1997-310
c.2

CANADE

APR 23 1

Possible Effects of Gas Caps on SAGD Performance

Alberta
ENERGY

March 1997

National Library of Canada Bibliothèque nationale du Canada

Disclaimer

The Alberta Department of Energy, the Alberta Energy and Utilities Board (EUB), and the authors make no warranty, express or implied, nor assume any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed in this report, or represents that its use would not infringe on privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trade mark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favouring by the department or the EUB. The views and opinions of authors expressed herein do not necessarily reflect those of the department or the EUB. The report has been made available to the public to share information and improve our understanding of the performance of the new SAGD technology.

Possible Effects of Gas Caps on SAGD Performance

William K. Good, P.Eng.[1], Claude Rezk, E.I.T.[1],
Brian D. Felty, P.Eng.[2]

[1] Alberta Department of Energy
[2] Alberta Energy and Utilities Board

March 1997

Contents

1.0 Executive Summary 1

1.1 Purpose of Study 1
1.2 Issues 1
1.3 SAGD Bitumen Recovery 1
1.4 Study Methodology 2
1.5 Simulation Results 2
1.5.1 Athabasca McMurray 2
1.5.2 Cold Lake Clearwater, Wolf Lake 3
1.5.3 Cold Lake Clearwater, Burnt Lake 4
1.6 Further Work 4

2.0 Introduction 5

3.0 Background 7

4.0 Methodology 9

4.1 Simulation of the SAGD Process 9
4.2 Commercial Predictions 10
4.3 Supply Cost Model 10

5.0 Effect of Gas Cap Depletion on SAGD Performance: Athabasca McMurray Formation 11

5.1 Geology 11
5.2 Bitumen Resource 11
5.3 Well-Pair Performance Simulations 11
5.3.1 Model Selection 11
5.3.2 Model Description 11
5.3.3 Simulation Results 12
5.4 Commercial Project 13
5.5 Social Supply Cost 13
5.6 Athabasca Gas Effects Summary 14

6.0 Effect of Gas Cap Depletion on SAGD Performance: Cold Lake Clearwater Formation, Wolf Lake 31

6.1 Geology 31
6.2 Bitumen Resource 31
6.3 Well-Pair Performance Simulations 31
6.3.1 Model Selection 31
6.3.2 Model Description 31
6.3.3 Simulation Results 32
6.4 Commercial Project 32
6.5 Social Supply Cost 32
6.6 Clearwater Wolf Lake Gas Effects Summary 33

7.0 Effect of Gas Cap Depletion on SAGD Performance: Cold Lake Clearwater Formation, Burnt Lake 44

7.1 Geology 44
7.2 Bitumen Resource 44
7.3 Well-Pair Performance Simulations 44
7.3.1 Model Selection 44
7.3.2 Model Description 44
7.3.3 Simulation Results 44

7.4 Commercial Project 45
7.5 Social Supply Cost 45
7.6 Clearwater Burnt Lake Gas Effects Summary 45

8.0 Summary of Findings 59

8.1 Athabasca McMurray Formation 59
8.2 Clearwater Formation, Wolf Lake 59
8.3 Clearwater Formation, Burnt Lake 59
8.4 Other Considerations 60

9.0 Further Work 61

10.0 Glossary 62

Social Supply Cost 62
Pattern Life 62
Calendar-Day Oil Rate (CDOR) 62
Cumulative Steam/Oil Ratio (CSOR) 62
Live Oil 62
Dead Oil 62
Viscosity 62
Heating Values of Natural Gas and Bitumen 62
Volume Equivalency 62

Appendix A 63

Well-Pair Economic Limit Assumptions and Artificial Lift Considerations

Appendix B 66

Economic Model Description and Capital and Operating Cost Assumptions

Appendix C 68

Multi-Well-Pair Numerical Model Development for Analyzing Gas Cap Effects

Appendix D 69

Gas Cap Effect Simulation Data Set and Results, Commercial Plant Utilization
and Detailed Plant Bitumen Forecasts and Undiscounted Costs for Athabasca McMurray

Appendix E 121

Gas Cap Effect Simulation Data Set and Results, Commercial Plant Utilization
and Detailed Plant Bitumen Forecasts and Undiscounted Costs for Clearwater Wolf Lake

Appendix F 162

Gas Cap Effect Simulation Data Set and Results, Commercial Plant Utilization
and Detailed Plant Bitumen Forecasts and Undiscounted Costs for Clearwater Burnt Lake

1.0 Executive Summary

1.1 Purpose of Study

In November 1995, the Alberta Department of Energy and the Alberta Energy and Utilities Board (EUB) initiated a series of modelling studies to assess the potential applicability of the Steam Assisted Gravity Drainage (SAGD) bitumen extraction process under a variety of reservoir conditions. SAGD is an in situ bitumen recovery process that has been successfully demonstrated at the Underground Test Facility (UTF) near Fort McMurray. Since this recovery technique has the potential to significantly increase bitumen production, there is a great deal of interest in determining the extent to which SAGD extraction may be affected by various reservoir conditions such as thickness, depth, pressure, oil saturation, and the presence of associated water and natural gas.

This report reviews possible effects of gas caps on SAGD performance in the Athabasca McMurray and Cold Lake Clearwater oil sands. It focusses narrowly on bitumen production using the SAGD process and did not address other issues such as the potential effects of SAGD on gas production. The study was initiated as an internal investigation by the department and the EUB to learn more about the applicability of the SAGD process and has been made available to the public for the purpose of sharing information and improving our understanding of this new technology. A companion report covers other aspects such as overburden thickness, reservoir thickness, and water zones.

This report should be regarded as a preliminary prediction of SAGD performance in the presence of gas caps. It must be emphasized that the findings are subject to a number of practical limitations. The computer model used for simulations of SAGD performance was calibrated using field data acquired at the UTF where the SAGD process has been tested and demonstrated. For this study, it was necessary to extend the model to represent reservoir characteristics not found at the UTF, most importantly the presence of associated gas caps. A number of assumptions were required in extending the model. Similarly, the phenomenon of steam behaviour in the gas cap, also included in the model, has not been validated against field data. The findings outlined in this report therefore reflect the assumptions made in setting up the model and the limitations of numerical simulation. Results presented are the considered opinions of the authors but their accuracy or usefulness cannot be warranted since they have not been field tested.

1.2 Issues

Accumulations of natural gas are sometimes found in geological strata above oil sands deposits in the same pool. These accumulations are referred to as *associated* gas caps. Gas occurring in separate pools is referred to as *non-associated* gas. Accumulations of associated gas are not well defined with respect to size, continuity, and the degree of pressure communication with the bitumen below.

In some of the oil sand areas, significant natural gas production has already taken place and additional production is planned. Meanwhile, the newly developed SAGD technology is increasingly being regarded as an economic, in situ method of producing bitumen. Like other in situ bitumen extraction techniques, the SAGD process depends on effective containment of pressurized steam within the bitumen pay zone. There are concerns that SAGD bitumen recovery may be affected by steam losses into associated gas caps. The extent of this steam loss may be influenced by the size and pressure of the gas zones. It is this issue that occupies the primary focus of the study described in this report. A companion study addressing the potential impacts of pay thickness, overburden thickness, and water-bearing sands on SAGD performance was also been carried out. The results of this study are also available from the department.

1.3 SAGD Bitumen Recovery

Steam Assisted Gravity Drainage (SAGD) is an in situ bitumen recovery process that was developed to recover bitumen from oil sands that are buried too deeply for surface mining, yet are too close to the surface for other in situ steam stimulation techniques that depend on higher pressures. In SAGD installations, access to the oil sands formation is gained by drilling pairs of wells from the surface. Advanced drilling techniques are used to extend these wells horizontally through the lower part of the pay zone. The horizontal well sections, lying parallel, one directly above the other, are spaced several metres apart. At start-up, steam is injected into both the upper and lower wells and flows back along the annulus between the inner tubing and the well casing, heating and mobilizing the viscous bitumen in the wellbore area. Once pressure communication has been established between the two wells and a steam chamber or oil-depleted zone has been formed, steam is injected via the upper (injector) well only, and the lower well becomes the producer.

During SAGD recovery, steam injected through the injector well flows through the depleted zone to the cold interface where it condenses, heating the bitumen. Mobilized bitumen drains by gravity to the lower production well and a steam chamber is formed. The force required to lift the

produced bitumen to processing facilities at the surface is provided mainly by the pressure within the steam chamber. Non-condensible gas is often injected to lighten the fluid column and augment this lifting action. As the pay zone is exploited, the steam chamber continues to rise and spread, eventually reaching the top of the oil-bearing formation or some other impermeable barrier. This stage of steam chamber development is considered to be the time during which steam breakthrough to an associated gas cap is most likely to occur. In proposed commercial projects, several SAGD well pairs are arranged in patterns with 70-90 m spacing between adjacent pairs. Using this type of configuration, neighbouring steam chambers eventually merge as the pay zone is depleted.

The SAGD process was pioneered by the Ministry of Energy through the Alberta Oil Sands Technology and Research Authority (AOSTRA) and its industry partners at the UTF in the Athabasca oil sands northwest of Fort McMurray. Field testing and demonstration began in 1987 following several years of planning and construction. By 1990, the proof-of-concept phase of the UTF project had reached a successful conclusion and the partners decided to proceed with the next phase, a pre-commercial demonstration of the SAGD process. Three new 600 m well pairs (500 m horizontal section) were completed in 1991 and initial steaming began a short time later. By 1993, individual UTF wells were among the top crude oil producers in Alberta. In 1995, two additional horizontal well pairs were drilled from the surface. These wells were tied into expanded process facilities in 1996.

The successful demonstration of SAGD technology at the UTF has stimulated the interest of several oil companies in developing commercial-scale SAGD projects.

1.4 Study Methodology

The numerical models used in the study are based on CMG STARS, an advanced process reservoir simulator calibrated on the basis of extensive SAGD performance data obtained at the UTF project. The model was modified to include a gas cap, the pressure and thickness of which could be varied. In addition, the model was adapted to simulate breakthrough of steam into the gas cap. These modifications necessitated a number of assumptions that are described in greater detail in the body of the report.

In this study, SAGD performance was simulated for the Athabasca McMurray oil sands and for the Cold Lake Clearwater oil sands at Wolf Lake and Burnt Lake. The UTF database provided useful information on SAGD performance at the UTF. Wolf Lake and Burnt Lake were sites for which information was readily available.

It must be stressed that the geology and reservoir characteristics of the UTF are not the same as at other locations in the deposit. In the Athabasca deposit, as well as Cold Lake, SAGD performance will be site-specific.

The models used for the simulations incorporated a number of parameters reflecting reservoir geology, selected SAGD well configurations, associated gas cap thickness, and whether or not gas caps had been depleted. Simulations were then run to provide performance predictions for various SAGD operating strategies in terms of operating pressure, steam rate, and production rates of bitumen (oil) and water for individual well pairs over the expected economic life of the wells.

The social supply cost of bitumen was calculated based on well-pair performance predictions and assumed capital and operating costs to provide a common basis for ranking the alternatives. The social supply cost represents the cost per unit of production over the project life that will provide the rate of return implied by the discount rate, before taxes and royalties. A discount factor of 10% was selected in this study. Simulations were run for 30,000 bbl/d commercial SAGD plants with lifetimes of 30 years. During the first 25 years, production from new SAGD well pairs comes on stream as older wells become depleted.

The supply costs used in this study are intended to provide a reasonable basis for ranking alternatives. A number of economic factors normally considered by companies in evaluating the potential profitability or viability of individual projects were intentionally omitted as beyond the scope of the study; these include royalties, tax implications, cash flow, and return on investment. Similarly, no consideration was given to potential impacts on government revenues. It should also be noted that this study considered only bitumen production; gas production revenues and costs were not calculated. A complete description of the economic calculations and the cost-related assumptions is given in Appendix B.

1.5 Simulation Results

In general, calculations based on the numerical simulations indicate that SAGD process costs depend on the amount of steam that flows into the gas cap, from which no bitumen is produced. However, it is assumed in the simulations that these losses can be reduced or largely eliminated by operating the process at or near the gas cap pressure. From the standpoint of SAGD performance, operating at a reduced pressure improves the heat efficiency of the steam due to increased latent heat. However, the temperature of the steam is also lowered. This results in smaller reductions in bitumen viscosity and reduced rates of bitumen production. Figure 1.1 illustrates some of the representative simulation results for three selected reservoirs having non-depleted and depleted gas caps of the thicknesses indicated.

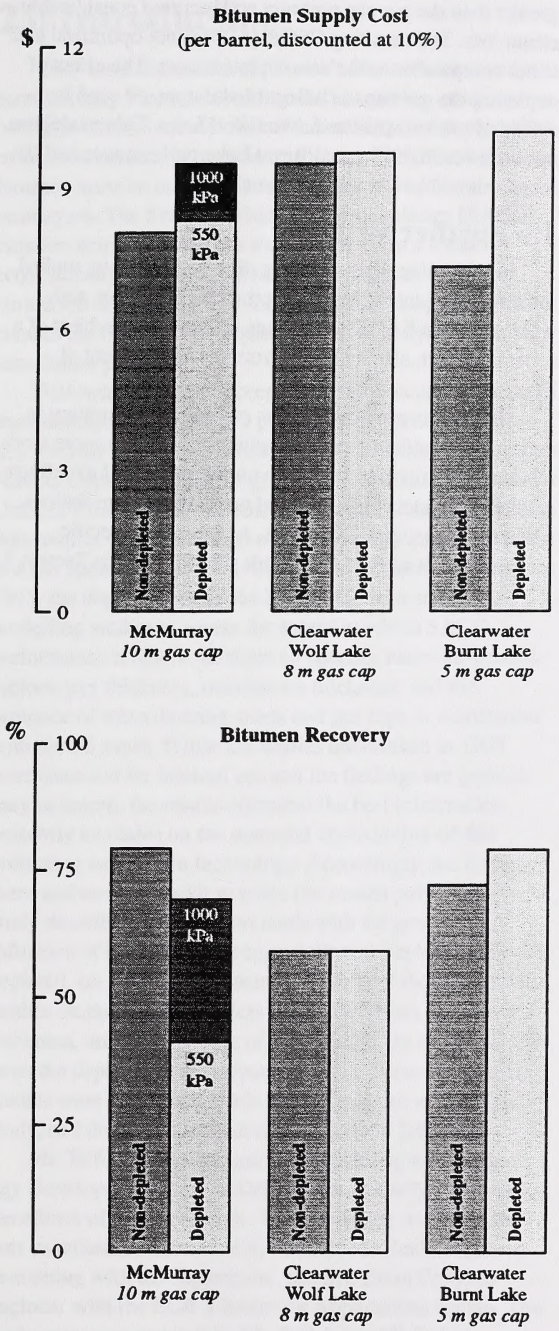


Figure 1.1 — Bitumen Supply Costs and Recovery

1.5.1 Athabasca McMurray

Results for Athabasca McMurray indicate that, in the absence of a gas cap and with the steam chamber operating at 2600 kPa (similar to the UTF project), a CDOR (calendar day oil rate) and CSOR (cumulative steam/oil ratio) of 80 m^3/d and 2.7, respectively, are achieved. Bitumen recovery is 81%. In the case of the thickest gas cap (10 m), SAGD performs very well when its operating pressure is 1800 kPa, the same as the gas cap. Although the CDOR of 71 m^3/d is reduced due to lower pressure, the CSOR, a good indicator of economics, is slightly better (2.6) due to more efficient use of steam at the lower pressure. In a case where the SAGD process is operated at the assumed depleted gas cap abandonment pressure of 550 kPa, the CSOR is only 1.9, while the CDOR is 25 m^3/d. Bitumen recovery, when the wells are run to their economic limit, is only 41%. Although believed to be reasonably well optimized, a 10 m depleted gas cap case operated with a steam chamber pressure of 1000 kPa, 450 kPa above the depleted gas cap pressure, yields a lower CDOR of 47 m^3/d and a higher CSOR of 3.4, respectively. Bitumen recovery in this case is 69%, down from 79% for the non-depleted case.

In summary, simulations indicate that pressure depletion in a 10 m thick Athabasca gas cap decreases the CDOR and increases the supply cost of bitumen, particularly if bitumen recovery is to be maximized. For thinner gas caps, the results indicate that bitumen tends to plug the gas cap, reducing steam losses and the impact of gas depletion on SAGD performance.

1.5.2 Cold Lake Clearwater, Wolf Lake

The Clearwater oil sand at Wolf Lake has a net pay of 52 m, about twice that of Athabasca McMurray. It also has lower permeability and about one half the oil saturation. As a result of the lower oil saturation, steam/oil ratios, which have the greatest impact on economics, are considerably higher than in Athabasca McMurray oil sand. This makes SAGD less attractive at Wolf Lake. It was found that steam injection pressure at Wolf Lake has to be much closer to gas cap pressure than in the Athabasca deposit because of a greater propensity for steam loss, due, in part, to the lower viscosity of Cold Lake bitumen. Simulations also show slightly lower CSORs and social supply costs with increasing gas cap thickness. This phenomenon is thought to result from the thermal insulating effect of the gas caps.

Using the 8 m gas cap cases to represent the results, a non-depleted gas cap gives a CDOR of 93 m^3/d, a CSOR of 3.29, and recovery of 58%. Assuming a depleted gas cap, the simulation predicts a CDOR of 52 m^3 of bitumen per day, a CSOR of 3.86, and similar recovery. The simulations show that the effect of depleting the gas caps is much less severe than for the more viscous bitumen in the Athabasca deposit. However, these results should be viewed with

caution. The model used has not been verified by actual Wolf Lake field performance. In addition, the effects of pressure differences between the injected steam and the reservoir are complicated by interaction with the more mobile bitumen and the presence of solution gas in much greater volumes than in Athabasca bitumen.

1.5.3 Cold Lake Clearwater, Burnt Lake

The Clearwater Burnt Lake model is 34 m thick. It has lower average permeabilities than the Athabasca McMurray and Wolf Lake models, but with 70% oil saturation, considerably higher than in the Wolf Lake model. Performance of SAGD at Burnt Lake is predicted to be considerably better than at Wolf Lake in terms of production rates, steam requirements, and social supply costs, primarily due to higher bitumen saturation. Simulation results for Burnt Lake indicate that steam injection pressures need to be maintained near the gas cap pressures to prevent steam loss.

With a non-depleted 5 m gas cap, a CDOR of 64 m^3/d, a CSOR of 2.74, and a recovery of 72.7% are predicted. The depleted gas cap predictions used a steam chamber pressure greater than the gas cap pressure and incurred considerable steam loss. The resulting CSOR (4.20) is not optimized and is not comparable to the non-depleted cases. The effect of depleting the gas caps in a Burnt Lake–type oil sand is expected to be similar to that for Wolf Lake. This model has not been verified by actual Burnt Lake performance and the results should be viewed with caution.

1.6 Further Work

In related work, the authors of this report have studied the effects of pay thickness, overburden thickness, and water sands on SAGD performance. This is the subject of a separate report, also available from the Department of Energy.

The results presented in this report are preliminary in nature, and require testing and calibration. Much more work remains to be done to ensure an understanding of the effects studied. This includes numerical and physical simulations, laboratory tests, and field pilots. A number of specific recommendations for future work are presented in Section 9.

2.0 Introduction

Only a small fraction of Alberta's bitumen resources are economically recoverable using surface mining methods, owing to the costs associated with handling and transporting overburden materials and the mined ore. The remaining bitumen must be extracted from the oil sands using in situ techniques. The Steam Assisted Gravity Drainage (SAGD) bitumen extraction process was conceived as a means of economically producing bitumen from oil sands that are buried too deep for surface mining, yet not deep enough to contain the relatively high pressures used in cyclic steam stimulation processes.

Following years of successful development, testing, and demonstration of the SAGD process at the Underground Test Facility (UTF) northwest of Fort McMurray, the Alberta Department of Energy and the Alberta Energy and Utilities Board (EUB) identified the need for additional information on the potential commercial applicability of the process for a range of reservoir conditions. In November 1995, the department and the EUB initiated a series of modelling studies to assess the extent to which SAGD performance might be affected by specific reservoir-related factors: pay thickness, overburden thickness, and the presence of water-bearing sands and gas caps in association with the oil sands. While the studies undertaken in 1995 were intended for internal use and the findings are preliminary in nature, the results represent the best information presently available on the potential applicability of this promising new in situ technology. Accordingly, the department and the EUB wish to make the results public. The study described in this report deals with the possible influence of associated gas caps, both non-depleted and depleted, on SAGD performance. Results of the companion studies on the possible effects of pay thickness, overburden thickness, and the presence of water sands are available from the department in a separate report. These companion studies were based on models similar to those used in this study, and did not address detailed reservoir lithology.

Mr. W.K. Good, manager of Engineering and Technology Development, Alberta Department of Energy, directed the efforts of the study team. The simulation work and the cost calculations were done by Mr. Claude Rezk, engineer-in-training with the department, and Mr. Brian Felty, an engineer with the EUB's Reservoir Applications Group. The study team was assisted by Mr. E.C. Lau of E.C. Lau Petroleum Consulting Inc.

Numerical modelling techniques were used to simulate SAGD performance. The model used, CMG STARS, was originally calibrated on the basis of SAGD performance at the UTF, where there is no gas cap. It was therefore necessary to incorporate a gas cap feature into the model and to include a mechanism for simulating flow behaviour when SAGD process steam reaches the gas cap. In the absence of applicable field data, a number of assumptions were used in making these modifications to the model. The model was also adapted to reflect selected SAGD well configurations, gas cap thickness, and whether the gas cap had been depleted. Modelling parameters were selected to represent some of the geological features of the three reservoirs studied—McMurray Formation sands in the Athabasca deposit and Clearwater Formation sands at Wolf Lake and Burnt Lake in the Cold Lake deposit (Figure 2.1). Useful information on SAGD performance at one site in the McMurray Formation was available from the UTF database. Wolf Lake and Burnt Lake had been sites of earlier test drilling. An overview of the modelling approach used is given in Section 4 and details of the well pair simulation models for the three different oil sands are given in Sections 5, 6, and 7.

Modelling SAGD performance in the proximity of associated gas caps is a technical challenge. Spatial discontinuities in the oil sands and their surroundings make it difficult to accurately represent important characteristics such as permeability, bitumen content, and gas cap association. In addition, some phenomena of interest, such as steam breakthrough, to be discussed later, are complex and transient in nature. The validity of results presented here is limited by the accuracy of the assumptions noted above, the complexity of the problem, and by the fact that history-matching data were available for just one field situation. While much work remains to be done, the results of this preliminary study do represent progress to date in assessing the potential range of applicability of SAGD technology.

Simulations were run to provide performance predictions for various SAGD operating strategies in terms of operating pressure, steam rate, and production rates of bitumen (oil) and water for individual well pairs over the expected economic lifetime of the wells. The results of well pair performance simulations were used in performing calculations concerning the economic performance of a commercial plant in which new well pairs are brought into production as older wells become depleted. Social supply costs of bitumen were calculated on the basis of several assumptions, including capital and operating costs. The social supply cost represents the cost per unit of production over the project life that will provide the rate of return implied by the discount rate, before taxes and royalties. A discount factor of 10% was selected. Social supply costs were based on 30,000 bbl/d commercial SAGD plants with lifetimes of 30 years.

It should be noted that the commercial predictions are based on assumptions intended only to provide a reasonable basis for comparison. The supply costs calculated are used

in this study to rank alternatives founded on similar assumptions. They should not be construed as predictions of project economics or viability. A number of economic factors normally considered by companies in evaluating the potential profitability or viability of individual projects were intentionally omitted as beyond the scope of the study; these include royalties, tax implications, cash flow, and return on investment. Likewise, no consideration was given to potential impacts on government revenues. It should also be noted that this study considered only bitumen production; no value was assigned to gas production. A complete description of the economic calculations and the cost-related assumptions is given in Appendix B.

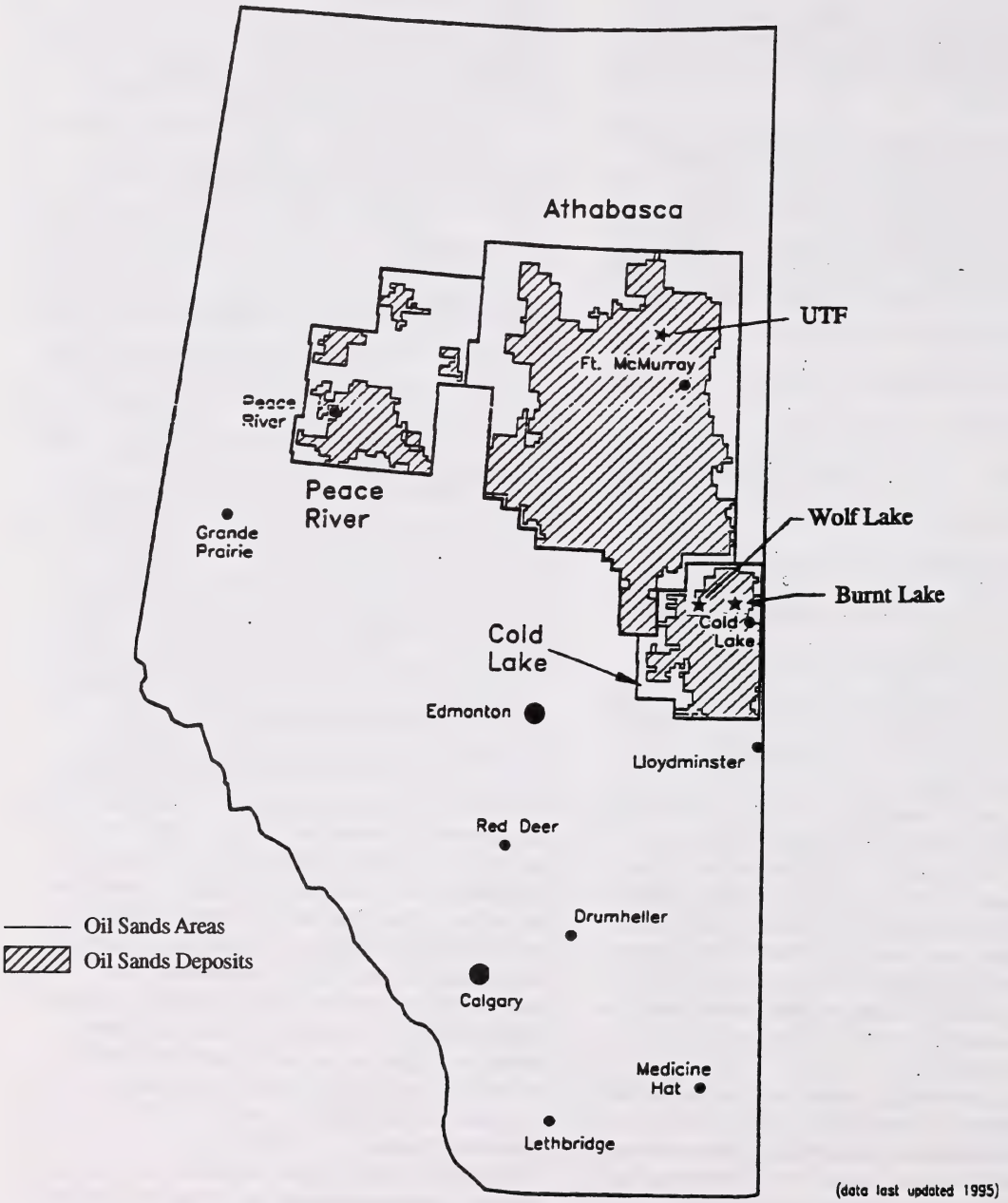


Figure 2.1 — Alberta Oil Sands

3.0 Background

The Steam Assisted Gravity Drainage (SAGD) process developed and tested at the UTF in the Athabasca oil sands (Figure 2.1) is showing significant economic potential, particularly in confined oil sands with reasonable net pay and overburden thickness. The process uses two horizontal wells: a producer near the bottom of the reservoir and an injector 5-10 m above the injector. At start-up, steam is injected down the tubing of both the injector and producer and returns along the annulus inside the casing to heat the wellbore area. Once fluid flow is established between the two wells, the producer is converted to production while the injector continues to inject steam, filling the pore space vacated by the bitumen. As the bitumen drains to the lower well by the force of gravity, a bitumen-depleted zone or steam chamber forms as shown in Figure 3.1.

The UTF project was initiated by the Alberta Oil Sands Technology and Research Authority (AOSTRA) in 1982 with a series of design studies employing a system of shafts and tunnels to provide access to the oil sands and a safe work environment for effective testing of in situ recovery processes. In 1986, AOSTRA made a further commitment to test the SAGD process in Phase A of the UTF project. The mine access facilities were completed and a custom drilling rig was fabricated, field tested, and reassembled in the underground tunnel to drill the horizontal test wells.

During the next two years, Phase A well tests proved highly successful. The SAGD process demonstrated a commercially viable combination of production rates, steam/oil ratios, and ultimate recoveries. Hence, in 1989, the Phase B SAGD test program was initiated by AOSTRA. Phase B was designed to confirm the necessary drilling accuracy and scale-up performance using three commercial-length well pairs of 600 m (500 m horizontal section). The three well pairs were spaced 70 m apart, each well pair consisting of a production well at the base of the oil sands and a steam injection well about 5 m above the production well.

The Phase B wells were steamed and produced in a warm-up phase from October 1991 to April 1992 using the smaller Phase A steam plant. The construction of the larger Phase B surface process facility was completed during the fall of 1992. By early 1994, total production in excess of

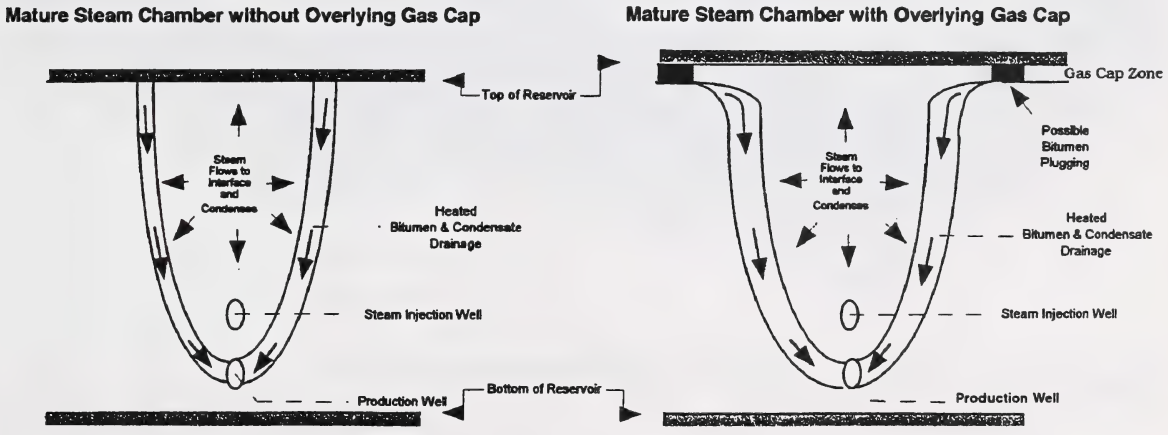

Mature Steam Chamber without Overlying Gas Cap
Top of Reservoir
Steam Flows to Interface and Condenses
Heated Bitumen & Condensate Drainage
Steam Injection Well
Production Well
Bottom of Reservoir
Mature Steam Chamber with Overlying Gas Cap
Gas Cap Zone
Possible Bitumen Plugging
Steam Flows to Interface and Condenses
Heated Bitumen & Condensate Drainage
Steam Injection Well
Production Well

Figure 3.1 — Steam Assisted Gravity Drainage Process

300 m^3 per day (2000 bbl/d) was reached, above original forecasts. In late 1995, two additional horizontal well pairs were drilled from the surface, demonstrating the technical capability to access to the buried oil sand without resorting to tunnels (Figure 3.2). These wells were then tied into expanded process facilities at the surface and started up in April 1996.

Due to the success of the Phase A and B wells, the "Commercial Plant Study for the AOSTRA Underground Test Facility" was conducted in 1994. This study was an assessment of the economic potential of SAGD for exploitation of the Athabasca oil sands. The study concluded that SAGD technology could be applied on a commercial basis. As a result of the positive results from the UTF project, the technology is being considered for application at other locations within the Athabasca McMurray Formation. Additional SAGD operations are underway in the Cold Lake oil sands (Burnt Lake and Wolf Lake in the Clearwater Formation) and one in a Lower Cretaceous heavy oil reservoir at Senlac, Saskatchewan, in the Lloydminster area.

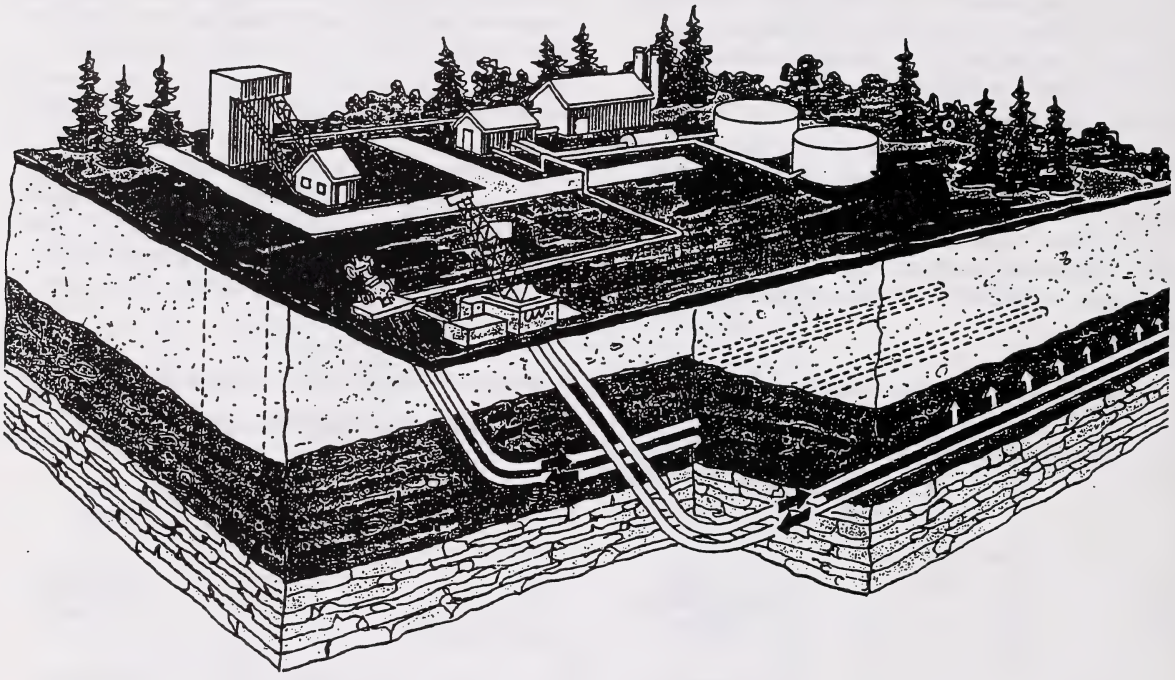


Figure 3.2 — Conceptual Diagram of the Surface-Access Dual-Well-Pair SAGD Process

4.0 Methodology

4.1 Simulation of the SAGD Process

The CMG STARS version 95.10 and 96 advanced process reservoir simulators used in this study were provided by the Computer Modelling Group (CMG). STARS was developed to simulate thermal/chemical processes including steam flooding, steam cycling, steam-with-additives, dry and wet combustion, and others, at both the field and the laboratory scale. For this study, the 128 MB RAM version was used due to the large number of grid blocks and fluid components needed to predict field-scale performance of the SAGD process.

The SAGD production profile consists of several distinct phases. These phases are described below in terms of idealized steam injection and bitumen production profiles, shown in Figure 4.1.

Wellbore heat-up and communication — In an actual SAGD installation, steam is circulated in both the injection and production wells by injecting down the tubing and producing hot water (condensed steam) back along the well annulus between the tubing and the liner and casing. This corresponds to **A** in Figure 4.1. In the simulator, "heaters" are used to provide the heat flux equivalent to the steam that would have been injected during a normal field start-up. The numerical values for the heat flux used in the model were determined from UTF field performance. The circulating pressure in the injection well is maintained slightly higher than in the production well. Oil sands between the injector and the producer are heated by conduction, reducing the viscosity of the bitumen. Bitumen begins to flow from the injector to the producer as a result of the pressure differential and gravitational force. The injector well is then converted gradually to steam injection and the producer to production. This process takes several months.

Vertical steam chamber development — This phase begins with communication between the two wells. With time, communication between the wells develops along their entire length and the steam chamber grows vertically. As the steam chamber grows vertically, the rate of bitumen production increases and generally peaks when the steam chamber reaches the top of the pay zone. This stage corresponds to **B** in Figure 4.1. Depending on formation thickness and the quality of the oil sand, it takes from 1 to 3 years from start-up to reach this stage.

Breakthrough — This term is used describe the phenomenon that occurs when the rising steam chamber comes in contact with the gas cap. A period of steam chamber pressure adjustment occurs as the chamber approaches the gas cap. If the steam chamber pressure is higher than in the overlying gas cap, it is believed that the steam will displace and work through the bitumen between the chamber and the gas cap. In the process of heating the gas sand and the gas and connate water in the sand, the

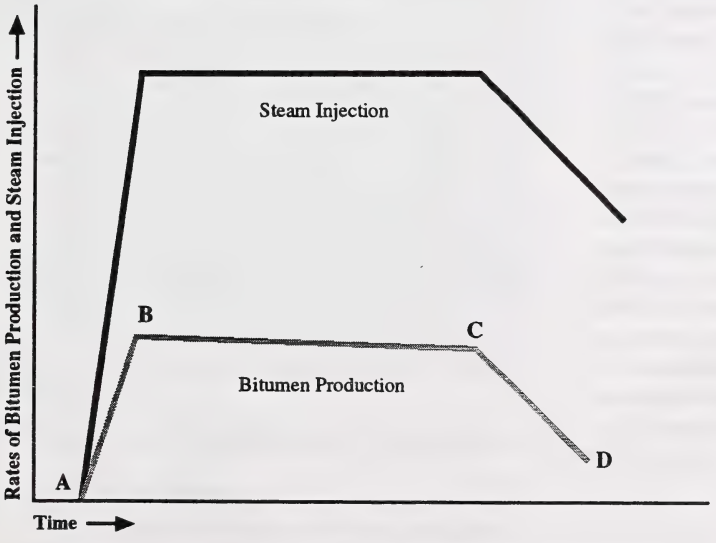


Figure 4.1 — Idealized SAGD Steam Injection and Bitumen Production Profiles

steam condenses, creating a zone of displaced bitumen, residual gas, and steam condensate ahead of the advancing steam. This mixture of gas, bitumen, and steam condensate is expected to act as a partial plug and restrict the movement of steam into the gas cap, particularly in thinner gas caps. In order to optimize project economics, steam injection rates, which are normally adjusted to maintain steam chamber pressure, would not be increased in the case of steam loss to a gas cap. Instead, the chamber pressure would be allowed to decline to an optimum level considering bitumen production rate and steam loss to the gas cap.

Lateral steam chamber development — Although some lateral development of the steam chamber occurred during the previous phase, it continues until adjacent chambers merge into one another. As shown in the figure, the bitumen (oil) production rate, although maintained relatively high, may decline slightly. The steam requirement may increase slightly as the chamber spreads and heat losses to the overburden increase. The merging of adjacent well patterns corresponds to **C** in Figure 4.1.

Wind-down — Once the steam chambers have merged, the average bitumen drainage height begins to decrease, resulting in a declining rate of bitumen production. The steam/oil ratio increases and, eventually, the well operation becomes uneconomic due a low bitumen production rate. The wind-down phase is represented by the portion of the curve between **C** and **D** in Figure 4.1. Steam injection may be discontinued at some point during the wind-down phase to optimize project economics.

Simulation of wellbore and reservoir interactions such as wellbore heat losses and frictional effects was not considered necessary. The simpler source-sink approach was used to represent injection and production wells.

The average well recovery factor was calculated by dividing the total bitumen produced during the economic well life (discussed later) by the original bitumen in place associated with the well length and a 90 m spacing between well pairs. In simulations of gas cap effects, this methodology results in higher recovery from the outside wells where bitumen is drained from beyond the well spacing area. The magnitude of this recovery difference is in the order of 3-4% for the outside well compared to the inner wells. Recovery is therefore given on an average well basis. In addition, no reduction in recovery was assigned to reserves between patterns, commercial projects, or non-developed areas.

Steam vapour withdrawal is detrimental to SAGD economics and the producer must be choked back to minimize this. To prevent steam from escaping from the steam chamber to the producer, the injection and production rates are balanced to maintain a small head of liquid above the production well. This is typically referred to as a "steam trap" or "sub-cool" control. Experience from the UTF mine-access SAGD wells has shown that optimal production requires sub-cool temperatures between 5°C and 10°C.

4.2 Commercial Predictions

The economic life for the average well pair was determined by calculating the net bitumen revenue and affordable steam cost (shown in more detail in Appendix A). In other words, when the net bitumen revenue becomes less than the total cost of the steam, fluid treatment, and well-pair operation, the well pair becomes uneconomic and is shut in. Well pair drilling schedules were prepared, based on well-pair simulated injection and production forecasts, to supply a 30,000 bbl/d plant for 30 years. A common scenario was used in each of the commercial simulations to maintain the plant at its bitumen capacity for the first 25 years. As plant production declined below a predetermined value, new well pairs were added. This scenario is described in Appendix B. Commercial plant economics were not optimized and results should be considered somewhat pessimistic. Steam chamber operating pressure, well spacings, and wind-down timing (the time at which steam injection to specific well pairs is discontinued) are aspects that should be investigated.

4.3 Supply Cost Model

A simple social supply cost model, developed by the Research and Technology Branch of the Department of Energy for use in a number of previous studies, is described in more detail in Appendix B and was used for each case. The discounted social supply cost of bitumen, often referred to as social supply cost or supply cost in this report, is obtained by dividing the discounted capital and operating costs (excluding royalties and taxes) by the discounted bitumen volume. The gas cost was assumed to be $2.20/GJ and a discount factor of 10% was used for all cases.

5.0 Effect of Gas Cap Depletion on SAGD Performance: Athabasca McMurray Formation

The intent of this portion of the study is to provide an understanding of the effectiveness of the SAGD process in the Athabasca McMurray Formation with various associated gas cap thicknesses at different reservoir pressures. The pressures were varied to determine the effect in each model of lower reservoir pressure as a result of gas production.

5.1 Geology

The McMurray Formation in the area of the UTF has been well documented. A reference log section of the McMurray oil sand is shown on Figure 5.1. The formation at the UTF is approximately 37 m thick with rich oil sands comprising the lower 15-20 m. The pay zone is separated by several shaly zones up to 1.7 m thick. It has been reported that these shales are either breccias or bioturbated shales that have not significantly limited vertical communication within the rich pay zone.

The horizontal and vertical absolute permeabilities at the UTF site are up to 10 and 5 Darcies, respectively. The oil sands also contain a relatively high bitumen saturation—greater than 10 mass per cent bitumen. The combination of high permeability and oil saturation and the absence of a water or gas cap made the UTF site a good candidate for development of SAGD technology.

5.2 Bitumen Resource

The Lower Cretaceous Wabiskaw/McMurray stratigraphic interval contains approximately 142 billion m^3 (892 billion bbl) bitumen in the Athabasca oil sands area, with the McMurray Formation containing most of the resource. The technical paper, "Applicability of the SAGD Process to the McMurray/Wabiskaw Deposit Athabasca Oil Sands Area," by B. Anderson et al. stated that over 100 townships meet reasonably strict geological criteria where SAGD recovery technology could be applied. This study was based on a review of four wells per township by the Alberta Geological Survey (AGS) and does not address local heterogeneity. The study assumed a minimum overburden of 30 m, continuous 6 (or greater) mass per cent bitumen, and no shale stringers greater than 2 m. It was determined that 56 billion m^3 of bitumen may be economically exploitable using SAGD technology.

5.3 Well-Pair Performance Simulations

5.3.1 Model Selection

Numerous detailed reservoir simulation studies have been conducted for the UTF and have led to a proven model for the McMurray oil sand at that site. For the purposes of this study, the sand properties at the UTF are considered typical for Athabasca McMurray oil sands and the basic model has been used in this study as the base case. Since the UTF model did not contain a gas cap, modifications to the model were necessary to study the effect of gas cap pressure on recovery and social supply costs.

A number of model configurations were tried in an effort to realistically represent the effect of a gas cap. Early simulation attempts used a modified UTF single half-well pair model. The gas cap pressure was simulated by placing a constant-pressure horizontal well diagonally and 90 m away from the well pair within the gas cap. Results for the single-well pair model were optimistic because the 180 m well-pair drainage area affected the production forecast. Subsequent attempts to represent inner, middle, and outer well performance by varying the gas withdrawals were unsuccessful. A multi-well pair model, although more complex, and having a larger number of grids, was ultimately selected.

5.3.2 Model Description

The multi-well pair 3D model selected for this portion of the study was developed from a version of AOSTRA's 2D UTF model as discussed in Appendix C. The 3D model has two layers in the j-direction, a "short circuit layer" of 100 m followed by a longer layer of 400 m, and matches the UTF performance. The short circuit layer has higher permeability than the longer or regular layer. The model contains two and one-half 500 m long well pairs spaced 90 m apart as shown in Figure 5.2. Descriptions of the petrophysical properties of the models, which are essentially the same as used for the bitumen pay section in previous UTF models, are provided in Table 5.1. The base case (no gas cap) contains 24 m of bitumen pay represented by twelve 2 m grid blocks in the vertical direction. The gas cap was modelled by extending the upper layer by 2.5 m grid blocks as required to obtain 5 m and 10 m gas cap thicknesses. The initial gas and water saturation in the gas cap were set at 80% and 20%, respectively. The model was extended laterally to 549 m or 180 grid blocks. A pressure sink was modelled by placing a horizontal well in the gas cap approximately 367 m laterally from the outside well pair. The pressure sink well in the gas cap maintained a constant back pressure equal to the initial reservoir pressure to eliminate pressure buildup in the model and to simulate a large associated gas cap where fluid leak-off from the model could occur.

5.3.3 Simulation Results

The following cases were simulated in this portion of the study:

Gas Cap Thickness (m)	High Initial Reservoir Pressure (1800 kPa)	Low Initial Reservoir Pressure (550 kPa)
0	✓	✓
5	✓	✓
10	✓	✓
10*+	✓	✓

All cases have 24 m of bitumen pay.

* Denotes cases using reduced steam injection pressure and rate after 1 year from start-up.

\+ Denotes cases using 2D and 3D models.

Simulation output performance curves showing reservoir pressure, steam injection rates, and bitumen and water production rates for each case are included in Appendix D. This output for each of the 2.5 well pairs, summarized on an average well-pair quarterly basis and used as the input data for further economic analysis, is shown in Figures 5.3 to 5.12 and summarized in Table 5.2.

As steam injection is initiated in the reservoir, the steam rate increases and the steam chamber grows vertically and laterally. The steam in the short circuit layer reaches the overlying gas cap earlier than in the regular layer. Once the steam reaches the top, heat losses begin and the steam rate reaches a maximum due to differences between the steam mobility in the bitumen zone and its mobility in the gas zone. However, the steam also mobilizes bitumen near the gas cap and displaces it into the gas cap. The mobility of the steam decreases as a partial plug is formed by the cooling bitumen. With time, the steam chamber in the regular layer also reaches the gas cap and a similar sequence of events, as explained earlier, is repeated. Hence, the steam rate increases and the peak extends over a longer time because the regular layer is four times longer than the short circuit layer. The steam also spreads laterally, allowing merging of the inner and middle steam chambers. As the steam rate declines in the inner and the middle well pairs, it remains high in the outer well pairs and steam continues to be lost to the gas cap.

The well pair configuration is very important in attempting to understand gas cap effects on SAGD performance. The inner and outer well pair performance can be modelled by using 2.5 well pairs. The inner steam chamber is pressure-supported from the adjacent middle steam chamber. Similarly, the middle steam chamber is pressure-supported (to a lesser degree) from the outer steam chamber. The outer steam chamber has no significant pressure support and loses steam to the gas cap. Due to the partial plugging and some pressure support, the steam rates for the inner and middle wells decrease whereas the outer well continues to lose steam.

It was found that the well-pair forecasts illustrate that, with the exception of the 10 m depleted gas cap, the bitumen production rates are similar, in the order of 90 to 100 m^3/d. The stable steam/oil ratios were higher for all gas cap cases, particularly for the 10 m gas caps. Steam injection rates were reduced in reruns of the 10 m gas cap cases, which lowered the SOR to a more acceptable level; however, bitumen production rates and recovery were reduced.

The water or the condensate production from the producing wells follows the steam rate profile to some extent. Initially, the water production from the inner well increases with a rising steam rate. Once the steam escapes to the gas cap in the short circuit layer, the water production drops sharply and then begins to increase. The water production increases with the steam rate until steam breakthrough occurs in the regular layer. The middle well-pair water production follows a similar trend initially. However, condensed steam from the inner well may increase (rather than decrease) water production in the middle well. This is also shown in the water production trend in the outer well.

The oil production rate increases corresponding to a drop in water production rate. This may be due to an increased steam-bitumen contact in the reservoir. The condensate may be "shielding" the bitumen and reducing its exposure to steam. However, with a constant steam rate and decreased condensate rate, more bitumen would be exposed to the steam.

Several sensitivity studies were performed because of various possibilities in designing a well operating scheme. The 10 m depleted gas cap case with steam reduction to 1000 kPa was selected to evaluate the effect of removing the "short circuit layer," making a 2D rather than a 3D model, and the effect of steam chamber pressure relative to the gas cap pressure as it relates to steam loss.

The combined properties in the short circuit and regular j-layers of the 3D model were selected to match UTF performance yet provide the ability to study early breakthrough. Modelling with 2D using the regular layer showed less than a 2% decrease in cumulative production in a half-year longer time period. The CSOR was increased from 3.38 for the original 3D configuration, to a value of 3.53 for the 2D case. Although it was expected that the 2D reservoir would be poorer, the small magnitude of the difference is surprising.

In a comparison using the 10 m depleted gas cap cases with and without steam reduction at the end of the first year, the reduced-steam case produces an 8.4% increase in

recovery and almost a 39% reduction in cumulative steam requirements. The operating life for the pressure-reduced case is increased by 4.25 years.

Operating the 10 m depleted gas cap case with a steam chamber pressure equivalent to the gas cap pressure of 550 kPa after one year minimizes steam requirements and steam loss. Recovery, however, is significantly reduced to roughly 41% and the operating life is extended by 1.25 years compared to the original case.

5.4 Commercial Project

The commercial plant well drilling and tie-in schedule and resulting bitumen and water production and steam injection rates are summarized for each case in Figures 5.13 to 5.22. The number of well pairs required to maintain the plant at capacity depends on the bitumen production rates per well pair and varies from 202 for the base case to 408 for the 10 m depleted gas cap case operated at 550 kPa.

The commercial plant forecast including the major capital and operating costs is provided in tables in Appendix D. The costs are presented for each case in undiscounted 1995 dollars on a yearly basis for the project life of 30 years.

5.5 Social Supply Cost

The social supply cost results for the 10 cases are provided in Table 5.2. The table gives major operating costs and capital costs and a production/injection summary and recovery for each case. The recovery and social supply costs are also summarized in Figures 5.23, 5.24, and 5.25. In summary, social supply costs are closely related to CSOR and are strongly affected by steam loss to the gas caps. For cases without gas caps, the social supply costs of bitumen are very similar at $9.12 and $9.15/bbl for the non-depleted and depleted cases, respectively. The non-optimized 5 m, non-depleted and depleted gas caps give supply costs of $9.83 and $10.25/bbl, respectively. The social supply costs for the 10 m gas cap cases range from $9.32/bbl for a no-steam leak-off case to $12.99/bbl for the case with the highest steam leak-off.

The UTF commercialization study reported the base case supply cost as $7.63/bbl. The higher supply cost for this study is supported by the differences between the two studies. In the commercialization study, the steam injection was suspended after 50% to 70% of the reserves had been recovered and the steam chamber was blown down until the economic limit was reached. In this study, the steam was injected until the well pair economic limit was reached. By operating the wells in this manner, bitumen recovery was maximized although the additional steam is less efficient and increases the supply cost.

5.6 Athabasca Gas Effects Summary

Social supply cost and bitumen recovery per well pair are the two factors used to determine the effect of associated gas pressure depletion. These factors are summarized as follows and plotted in Figures 5.23, 5.24, and 5.25.

A 10 m gas cap, studied most extensively, indicates less bitumen plugging than observed in the 5 m gas caps. In the non-depleted case, the lowest social supply cost and highest bitumen recovery of $9.04 per barrel of bitumen and 79%, respectively, are obtained when steam leak-off is minimized. In the depleted case, the social supply cost is lowest at $9.32 per barrel of bitumen when steam leak-off is minimized. Recovery, however, is very low, at only 41%. By operating at a steam chamber pressure of 1000 kPa compared to a gas cap pressure of 550 kPa, recovery is maximized at about 69% at a social supply cost of $10.53 per barrel of bitumen. In summary, it appears that depletion of thick gas cap pressures in Athabasca where the gas cap is in direct contact with bitumen may result in a loss of recovery of about 10% and an increase in social supply cost up to $1.50 per barrel of bitumen.

Gas Cap Thickness (m)	Initial Reservoir Pressure (kPa)	Steam Chamber Pressure (kPa)	Social Supply Cost ($/bbl)	Recovery (%)	CDOR (m^3/d)	Cum. SOR
0	550	2600	9.15	81	80	2.7
10*α	550	1000	12.25	68	44	3.53
5	550	2600	10.25	80	72	3.5
5	1,800	2600	9.83	80	75	3.2
10	550	2600	12.99	63	69	5.1
0	1,800	2600	9.12	82	79	2.7
10	1,800	2600	10.62	76	76	3.6
10*♦	550	1000	10.53	69	47	3.4
10*■	550	550	9.32	41	25	1.91
10*◆	1,800	1800	9.04	79	71	2.6

All cases have 24 m of bitumen pay.

* Denotes reduced steam cases.

♦ Denotes case where steam injection pressure was reduced to 1000 kPa after 1 year of operation.

■ Denotes case where steam injection pressure was reduced to 1875 kPa after 1 year of operation.

◆ Denotes case where steam injection pressure was reduced to 550 kPa after 1 year of operation.

α Denotes case where j=1 was removed. (2D model).

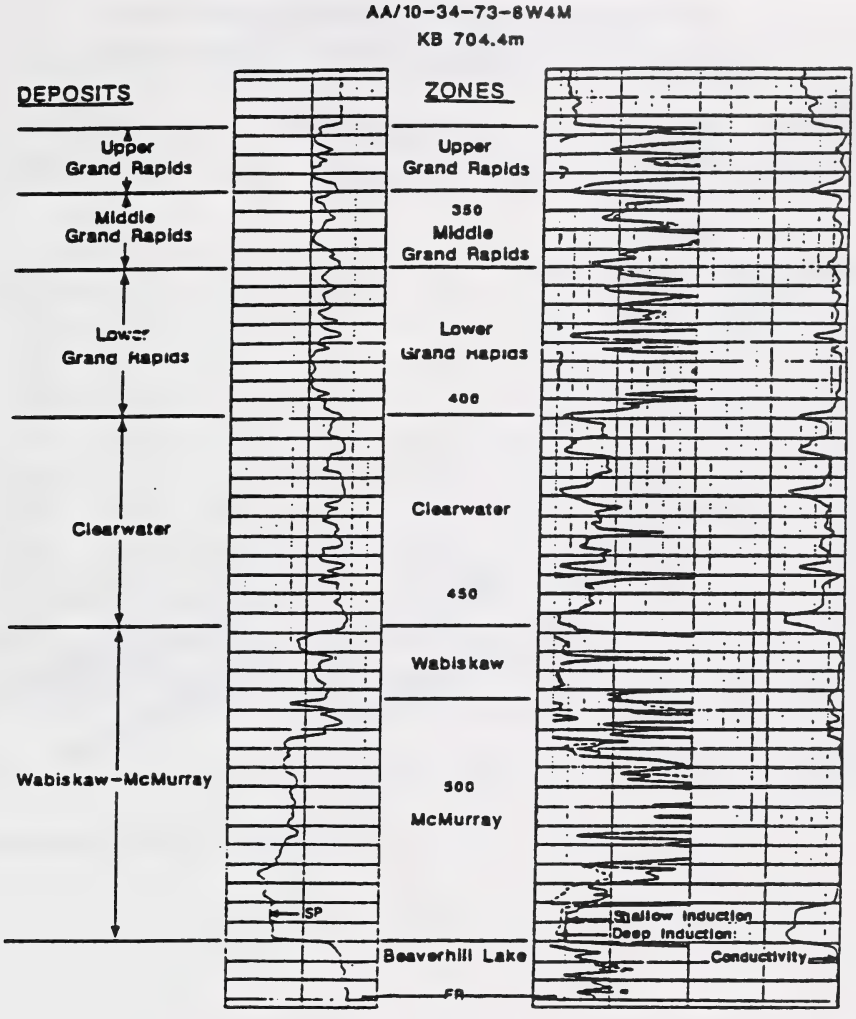


Figure 5.1 — Athabasca Oil Sands Area Reference Well
Cretaceous Section
PEX KIRBY EX 10-34-73-08W4M

ATHABASCA MCMURRAY FORMATION
RESERVOIR PARAMETERS FOR 3D MODEL

	J=2 (400 m)					J=1 (100 m)				
GRID NO.	Phi	Sw	So	Ki=Kj	Kk	Phi	Sw	So	Ki=Kj	Kk
13 - ?	0.30	0.20	0.00	2000	200	0.30	0.25	0.75	2000	200
12	0.30	0.25	0.75	2000	200	0.30	0.25	0.75	2000	200
11	0.30	0.25	0.75	2000	200	0.30	0.25	0.75	2000	200
10	0.30	0.25	0.75	2000	200	0.30	0.25	0.75	2000	200
9	0.30	0.25	0.75	2000	200	0.30	0.25	0.75	2000	200
8	0.35	0.15	0.85	10000	2500	0.30	0.25	0.75	2000	200
7	0.35	0.15	0.85	10000	2500	0.35	0.15	0.85	10000	5000
6	0.30	0.25	0.75	2000	200	0.35	0.15	0.85	10000	5000
5	0.35	0.15	0.85	10000	2500	0.35	0.15	0.85	10000	5000
4	0.30	0.25	0.75	2000	200	0.35	0.15	0.85	10000	5000
3	0.35	0.15	0.85	10000	2500	0.35	0.15	0.85	10000	5000
2	0.35	0.15	0.85	10000	2500	0.35	0.15	0.85	10000	5000
1	0.35	0.15	0.85	10000	2500	0.35	0.15	0.85	10000	5000

2m grid blocks in the k direction

Table 5.1

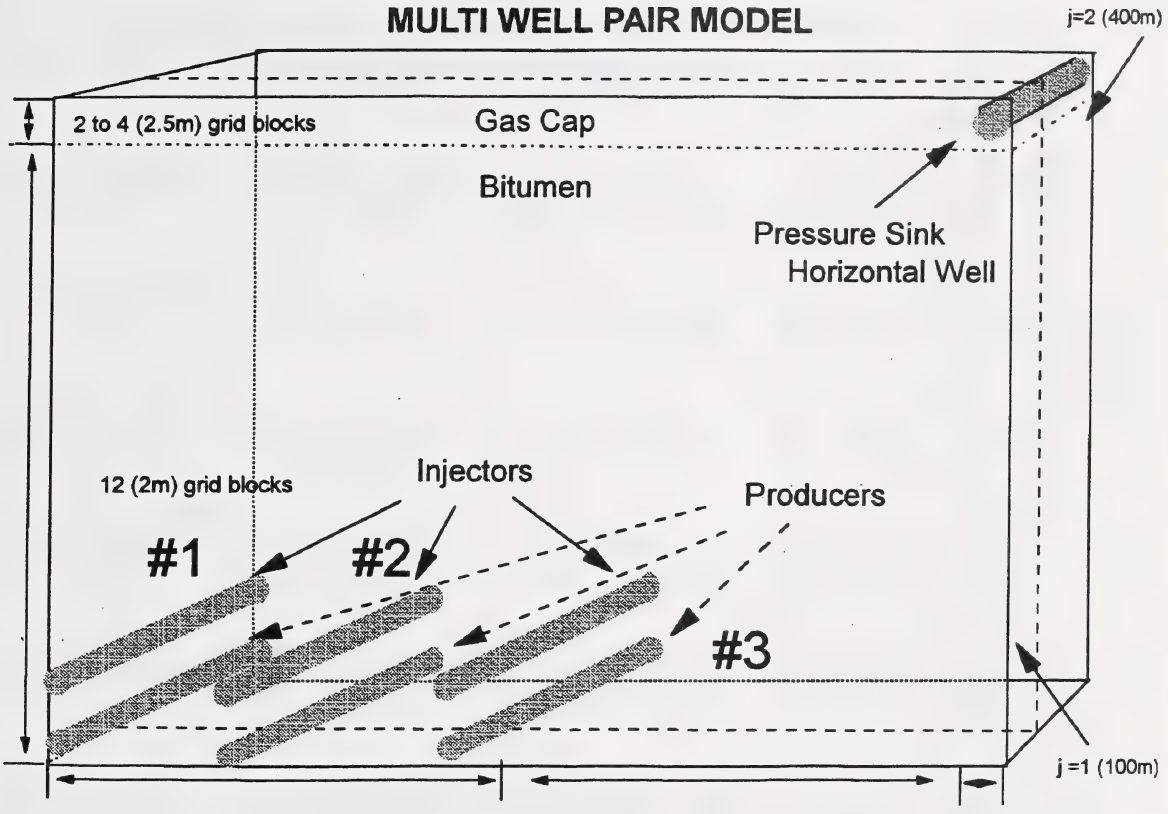


Figure 5.2 — Schematic of 3D Multi-Well-Pair Model

Table 5.2

Athabasca McMurray Gas Effect Study — Supply Cost Summary

Discounted @10% to 1995 Dollars

Cost Centre	0m Gas Cap Depleted Supply Cost	0m Gas Cap Non-depleted Supply Cost	5m Gas Cap Depleted Supply Cost	5m Gas Cap Non-depleted Supply Cost	10m Gas Cap Depleted Supply Cost	10m Gas Cap Non-depleted Supply Cost	10m Gas Cap — OPT Depleted Supply Cost	10m Gas Cap — OPT-550 Depleted Supply Cost	10m Gas Cap — OPT Non-depleted Supply Cost	10m Gas Cap — OPT–2D Depleted Supply Cost
Capital Cost										
Drilling	$11.13	$11.16	$11.56	$11.49	$13.20	$11.80	$14.07	$19.54	$11.98	$17.71
Seism/Delin/Eng	$0.32	$0.32	$0.31	$0.32	$0.33	$0.32	$0.32	$0.32	$0.31	$0.40
Steam Facilities	$4.76	$4.72	$5.88	$5.35	$9.06	$6.40	$6.16	$3.25	$4.69	$7.05
Other Facilities	$12.60	$12.64	$12.53	$12.62	$13.35	$12.80	$12.93	$12.87	$12.48	$15.82
Total Capital	$28.81	$28.83	$30.28	$29.78	$35.95	$31.32	$33.48	$35.98	$29.47	$40.98
Operating Cost										
Gas Cost	$15.69	$15.53	$19.98	$18.26	$28.88	$20.82	$18.88	$11.08	$14.77	$20.12
Utilities	$4.20	$4.16	$5.35	$4.89	$7.72	$5.58	$5.09	$2.97	$3.96	$5.45
Production Treating	$0.78	$0.78	$0.78	$0.78	$0.79	$0.78	$0.78	$0.78	$0.78	$0.81
Water Treating	$1.20	$1.20	$1.30	$1.25	$1.13	$1.35	$0.98	$0.85	$1.10	$1.11
Fixed and Other	$6.84	$6.86	$6.80	$6.85	$7.25	$6.95	$7.02	$6.98	$6.77	$8.59
Total Operating Cost	$28.71	$28.52	$34.21	$32.03	$45.77	$35.48	$32.75	$22.66	$27.38	$36.08
Total Cost/m3 BIT	$57.52	$57.35	$64.49	$61.81	$81.72	$66.80	$66.24	$58.64	$56.85	$77.06
Total Cost/bbl BIT	$9.15	$9.12	$10.25	$9.83	$12.99	$10.62	$10.53	$9.32	$9.04	$12.25
Plant Summary										
Number of Wells	202	202	212	212	248	222	258	408	220	240
Cum Bitumen Produced (E3m3)	46,754	47,297	48,000	48,049	44,944	47,926	46,539	46,087	48,664	40,329
Cum Steam Injected (E3m3)	133,320	133,872	175,016	160,717	241,894	183,538	164,882	91,810	132,432	151,590
Cum Water Produced (E3m3)	122,936	123,849	137,882	132,256	110,993	143,638	100,142	84,721	117,694	97,342
Plant CDOR (m3/d)	4,270	4,319	4,384	4,388	4,104	4,377	4,250	4,209	4,444	3,683
Plant CSOR (m3/m3)	2.85	2.83	3.65	3.34	5.38	3.83	3.54	1.99	2.72	3.76
Bitumen Capacity Utilization	89.5%	90.6%	91.9%	92.0%	86.1%	91.8%	89.1%	88.2%	93.2%	77.2%
Steam Capacity Utilization	81.0%	82.4%	85.6%	87.1%	81.9%	84.0%	79.4%	55.8%	80.9%	93.0%
Avg. Well Summary										
Pattern Life (yrs)	8	8.25	8.75	8.5	7.25	8	11.5	12.75	8.75	12
Cum Bitumen Produced (E3m3)	234	237	231	232	181	221	197	118	228	194
Cum Steam Injected (E3m3)	634	641	804	738	928	806	668	226	597	685
Cum Water Produced (E3m3)	616	624	668	641	448	665	428	219	558	462
Well CDOR (m3/d)	80	79	72	75	69	76	47	25	71	44
Well CSOR (m3/m3)	2.72	2.70	3.48	3.19	5.12	3.64	3.38	1.91	2.62	3.53
Recovery (90m spacing)	81.1%	82.3%	80.1%	79.6%	63.4%	76.2%	68.7%	41.4%	78.6%	68.2%

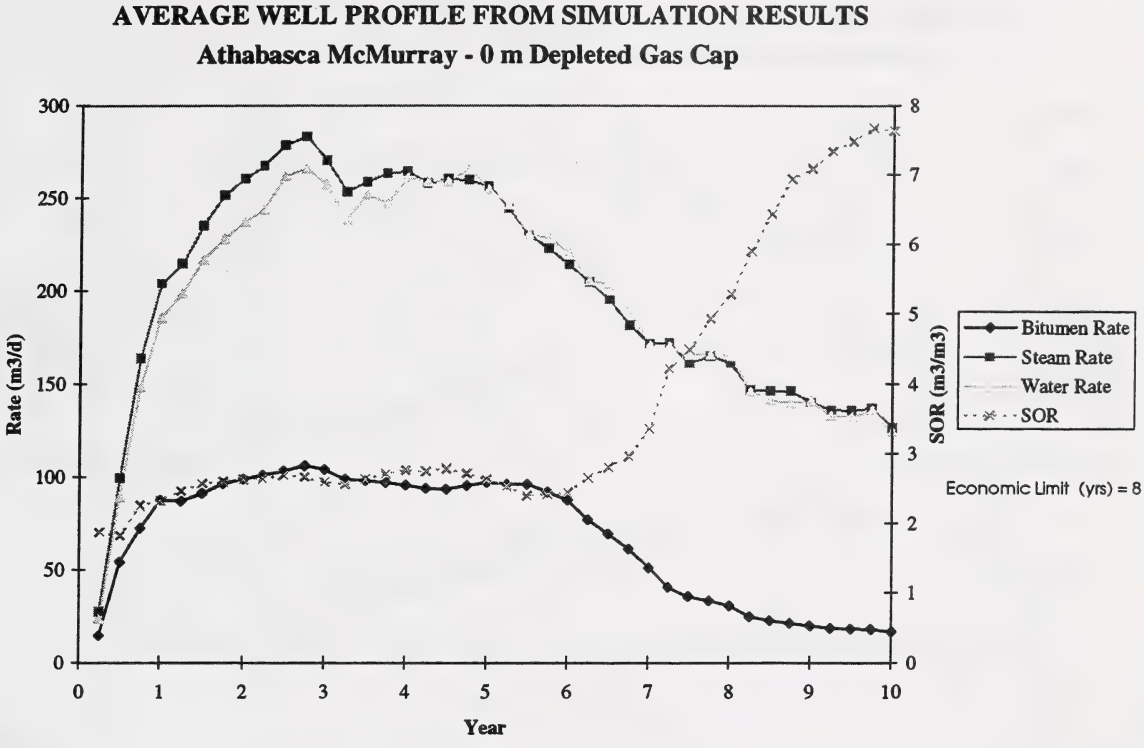


Figure 5.3

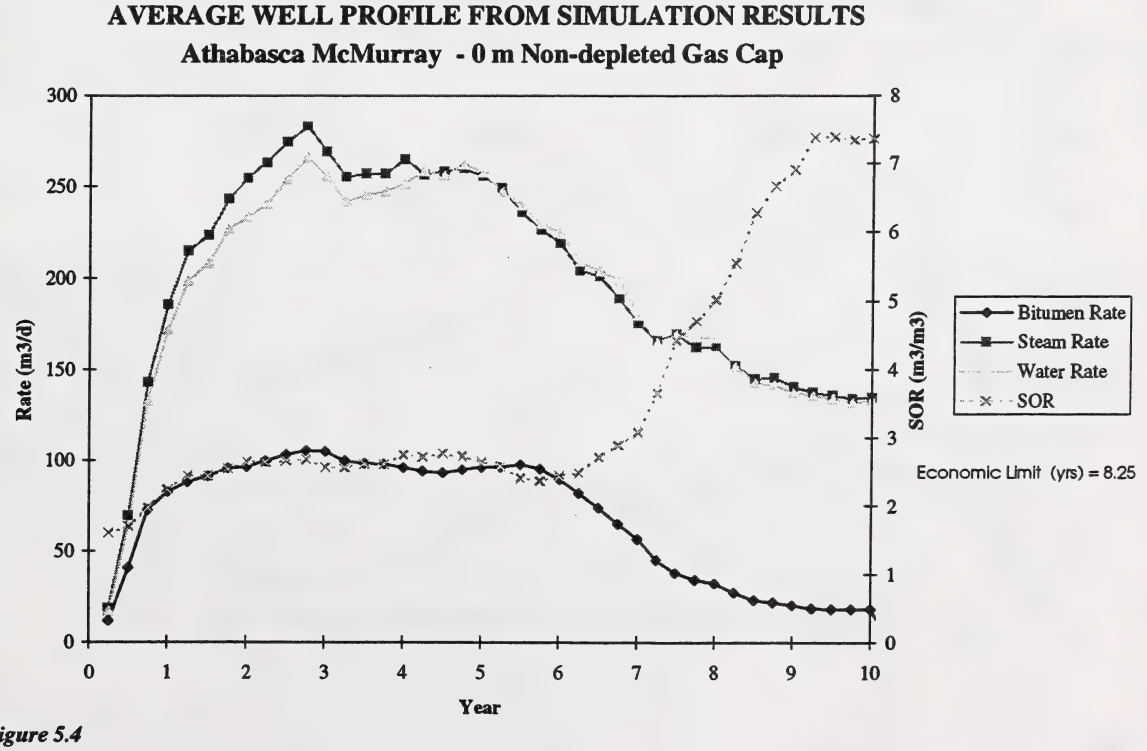


Figure 5.4

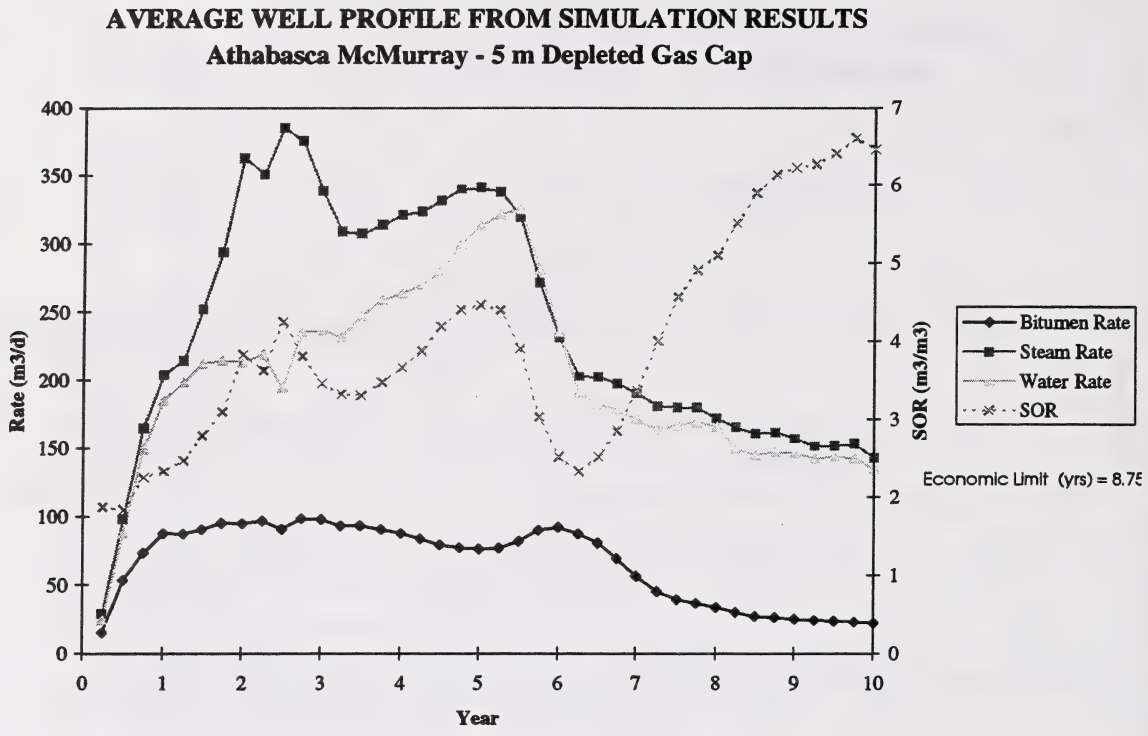


Figure 5.5

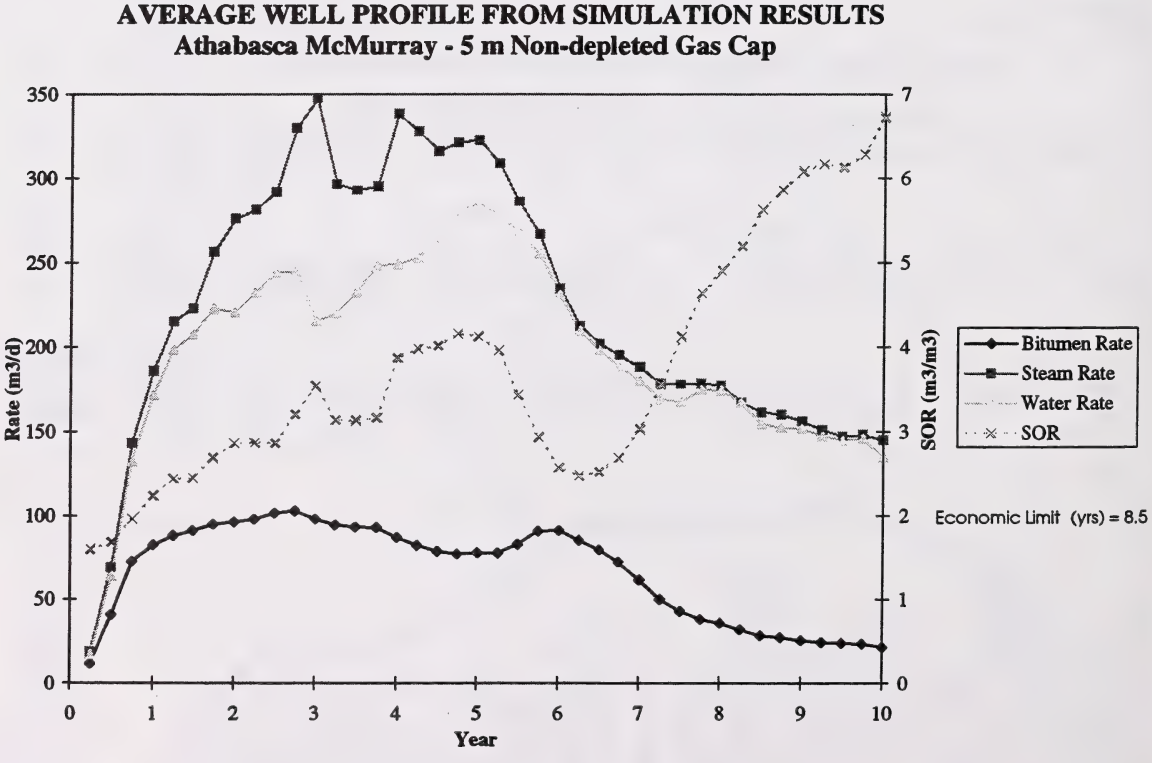


Figure 5.6

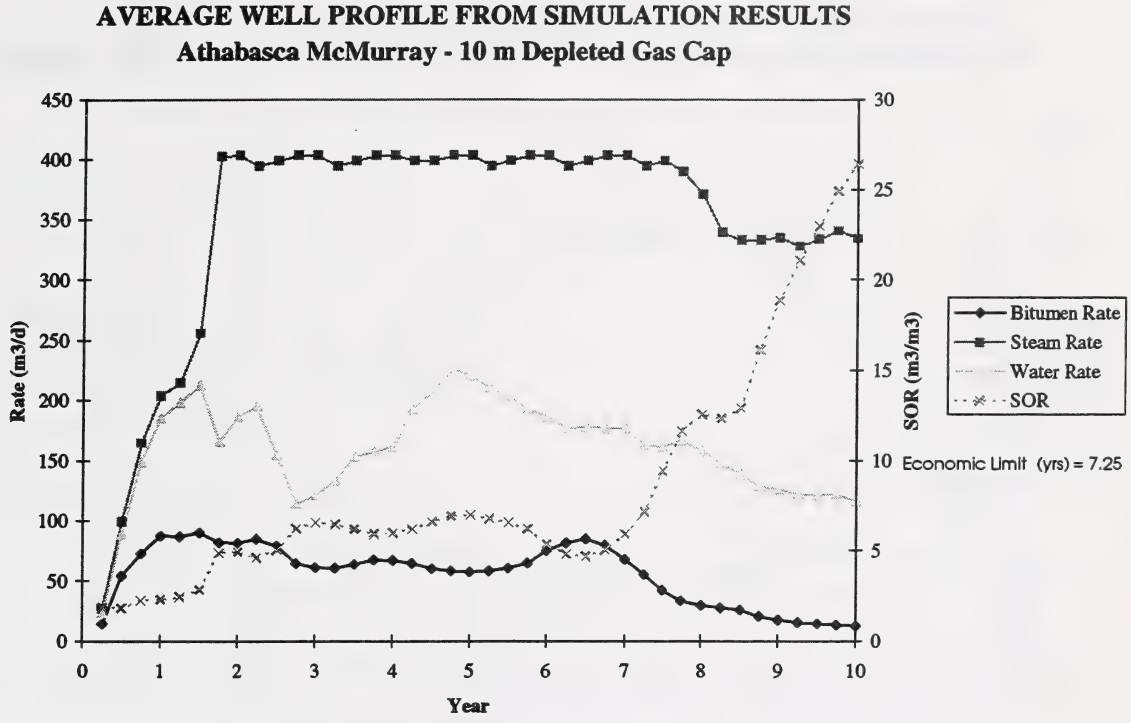


Figure 5.7

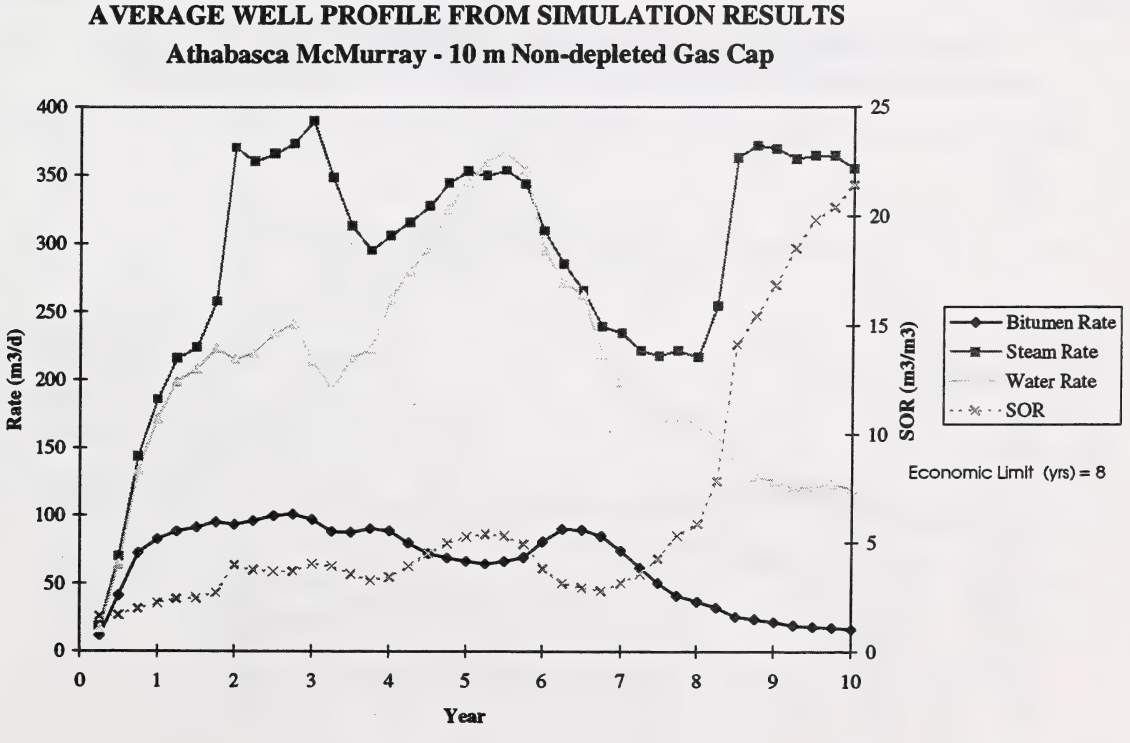


Figure 5.8

AVERAGE WELL PROFILE FROM SIMULATION RESULTS
Athabasca McMurray - 10 m Depleted Gas Cap - OPT (1000 kPa)

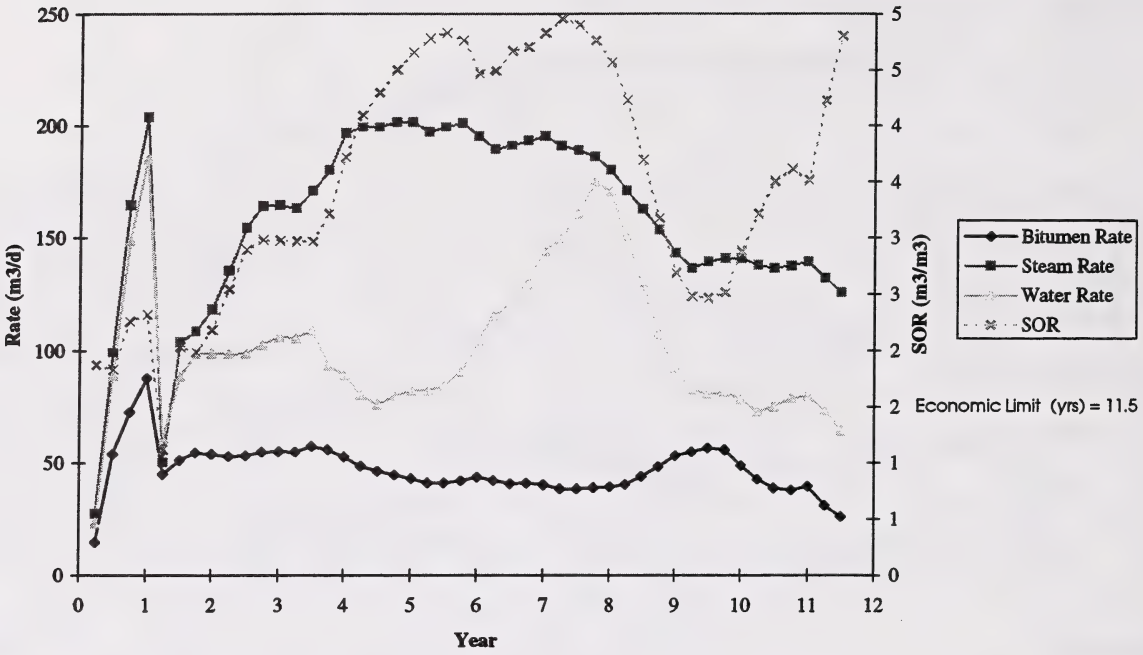


Figure 5.9

AVERAGE WELL PROFILE FROM SIMULATION RESULTS
Athabasca McMurray - 10 m Non-depleted Gas Cap - OPT (1800 kPa)

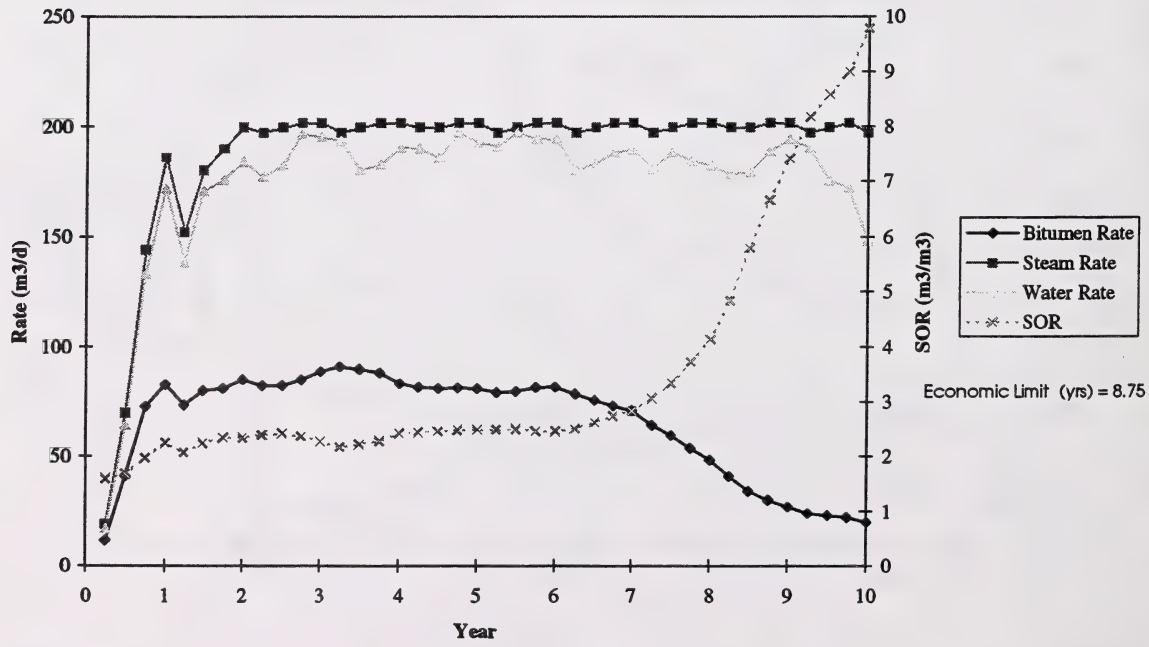


Figure 5.10

AVERAGE WELL PROFILE FROM SIMULATION RESULTS

Athabasca McMurray - 10 m Depleted Gas Cap (Injection reduced to 550 kPa after 1 yr)

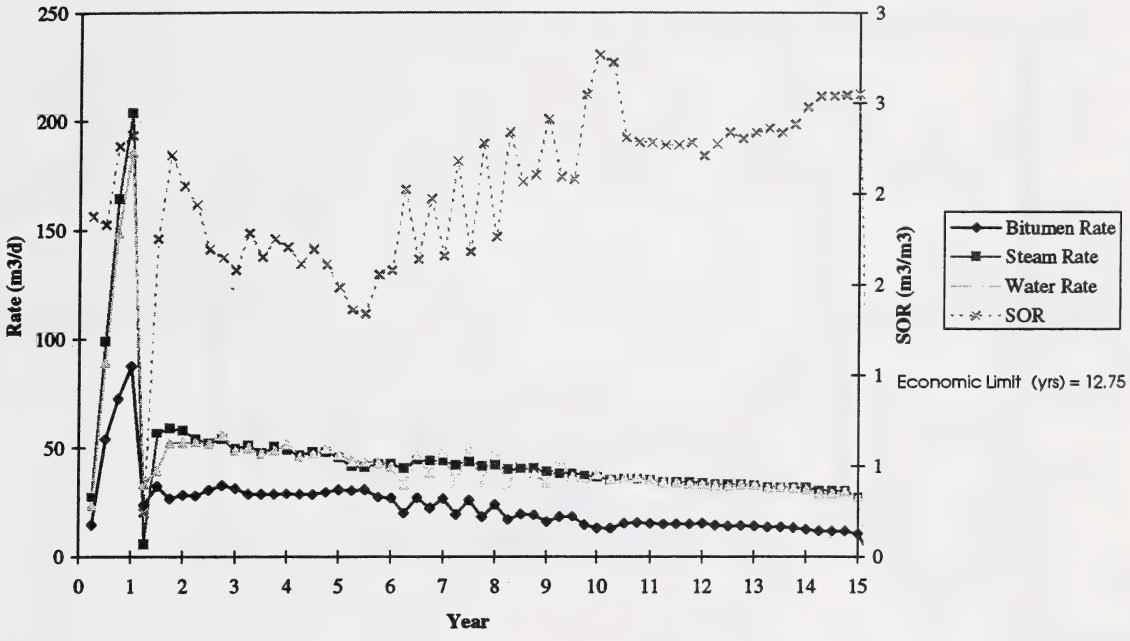


Figure 5.11

AVERAGE WELL PROFILE FROM SIMULATION RESULTS

Athabasca McMurray - 10 m Depleted Gas Cap - OPT (2D)

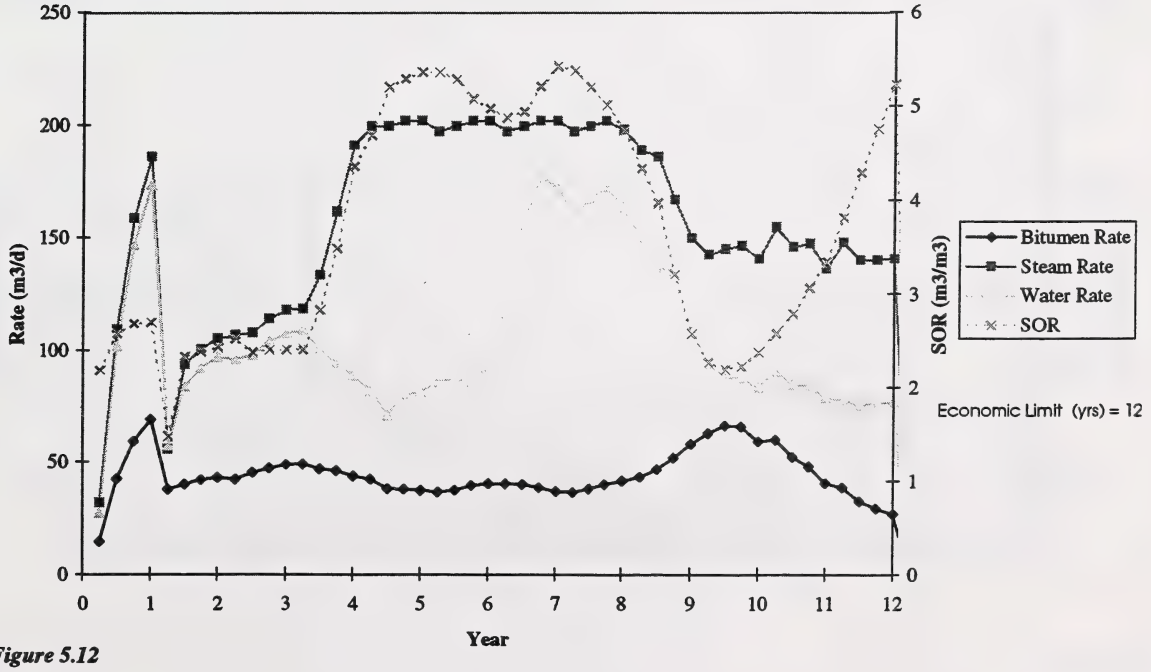


Figure 5.12

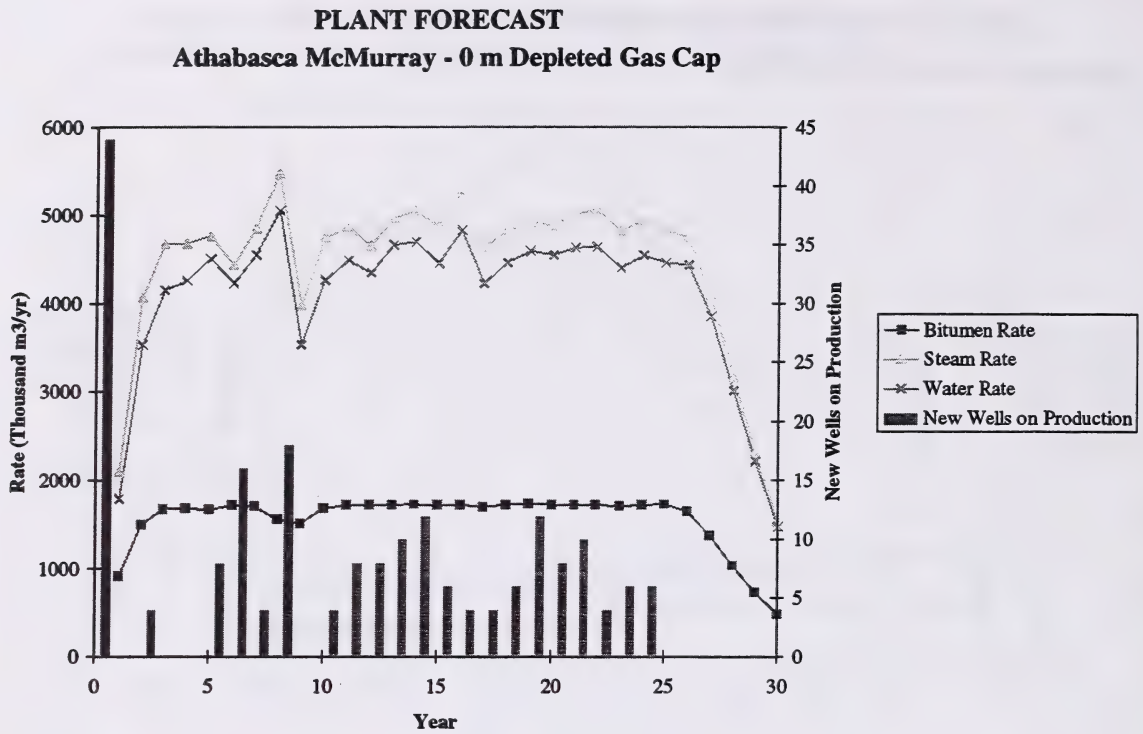


Figure 5.13

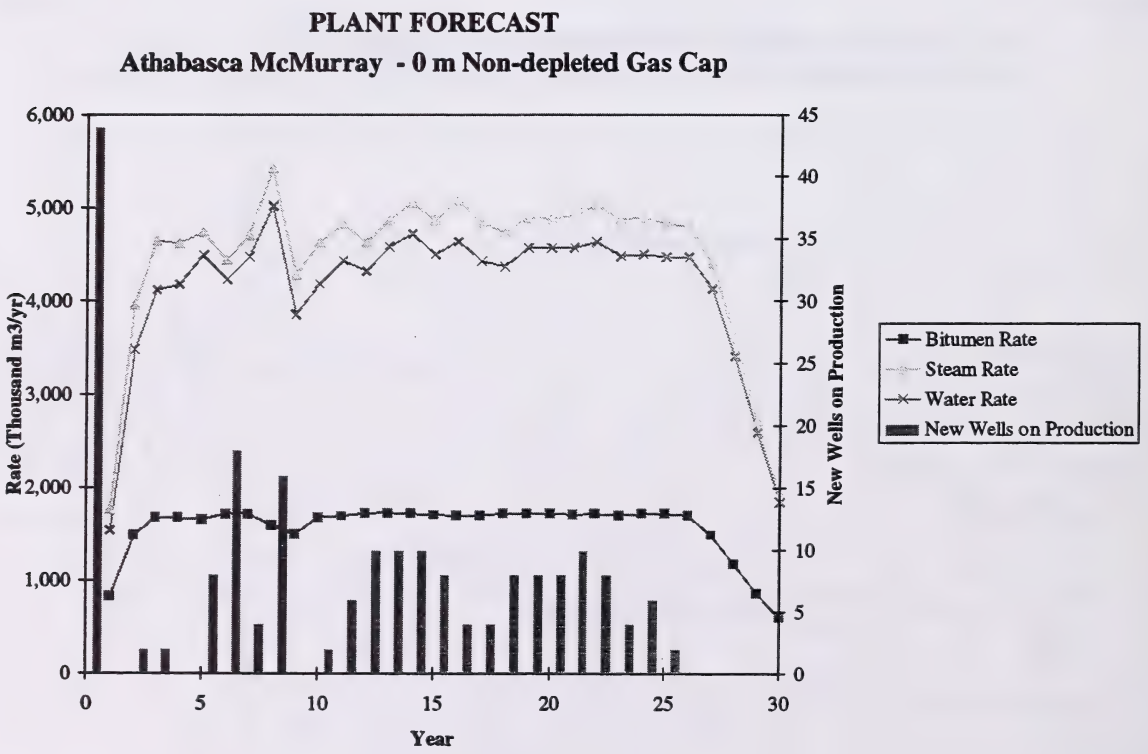


Figure 5.14

PLANT FORECAST
Athabasca McMurray - 5 m Depleted Gas Cap

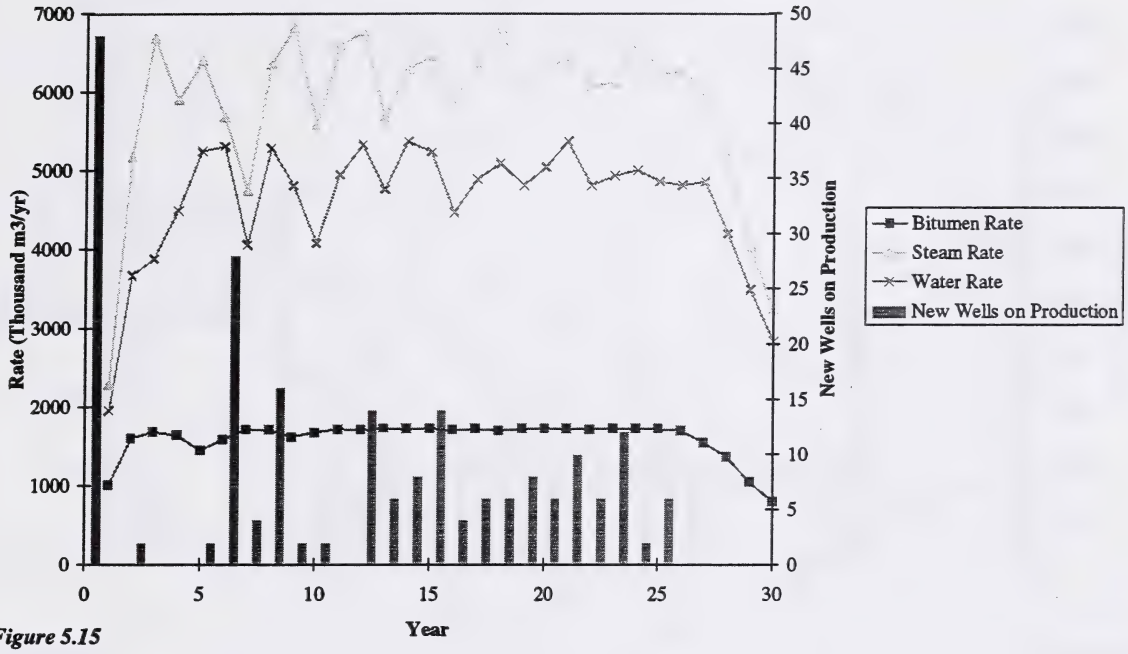


Figure 5.15

PLANT FORECAST
Athabasca McMurray - 5 m Non-depleted Gas Cap

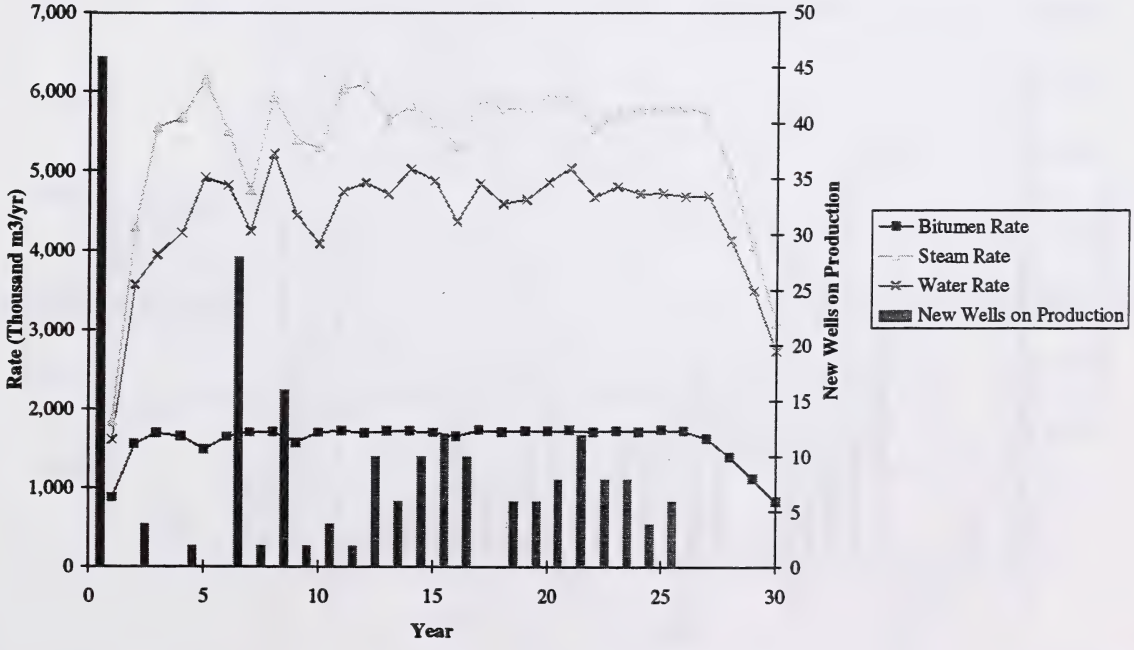


Figure 5.16

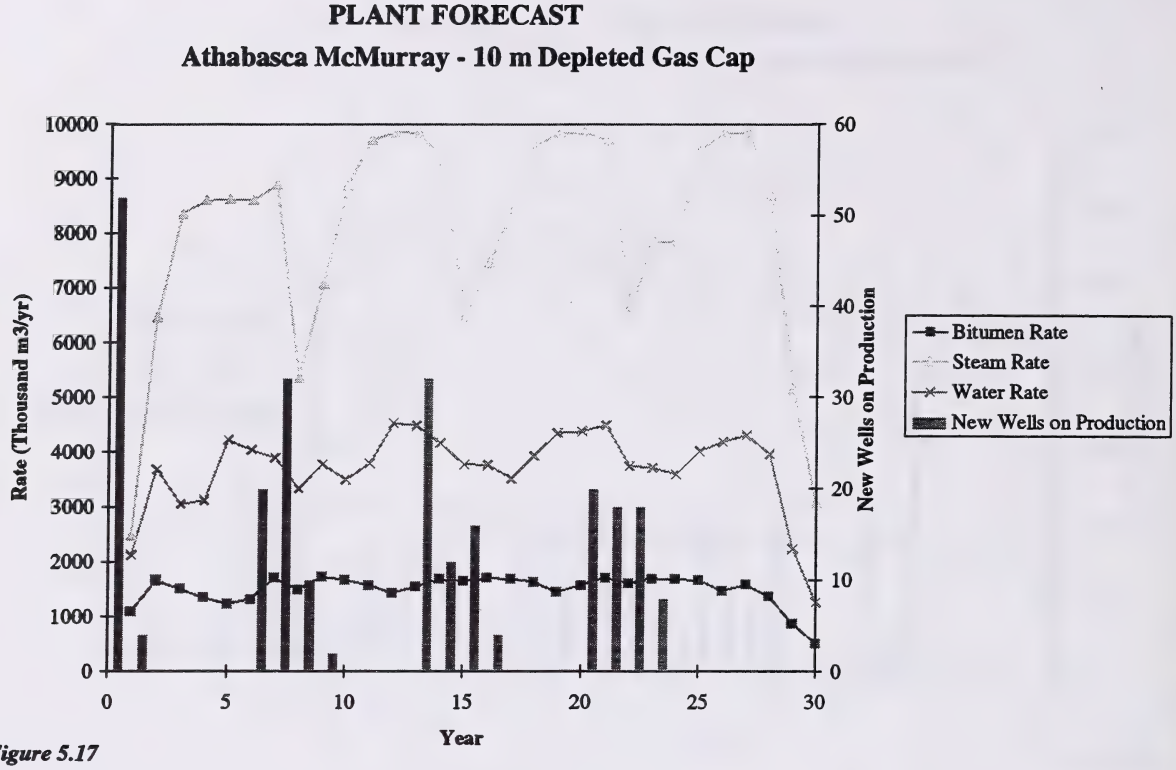


Figure 5.17

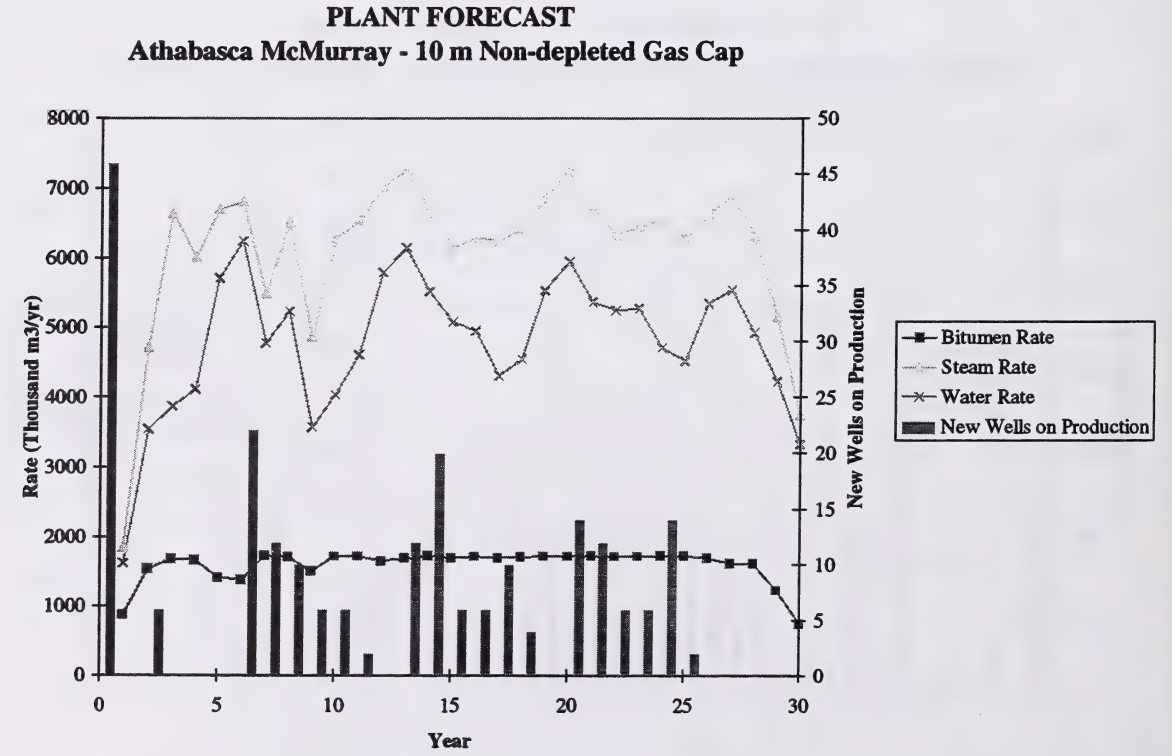


Figure 5.18

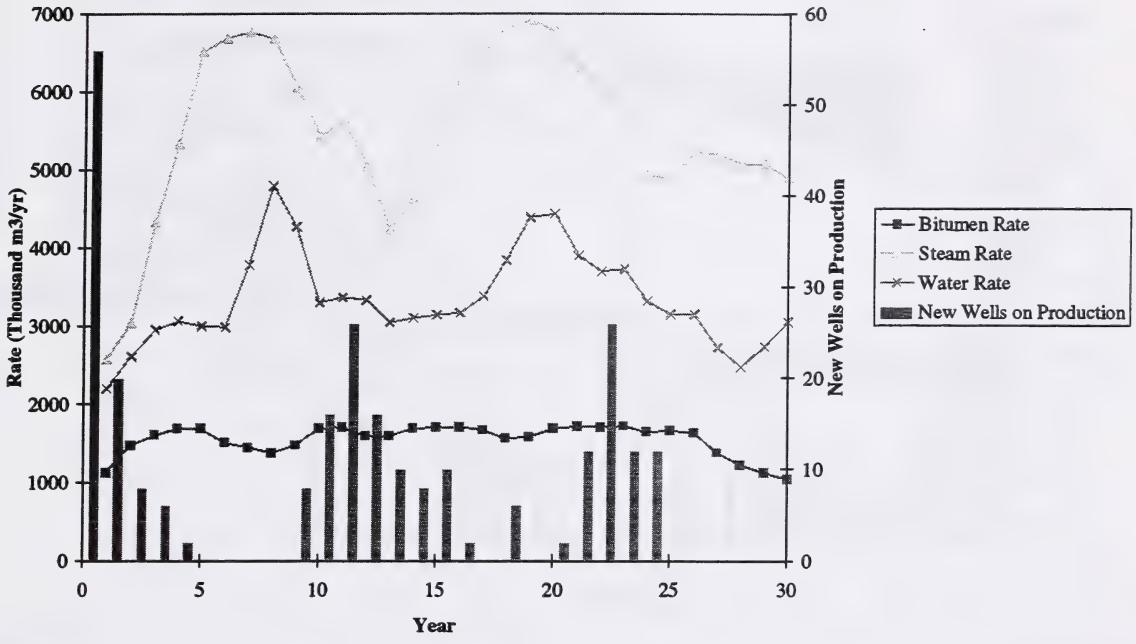


Figure 5.19

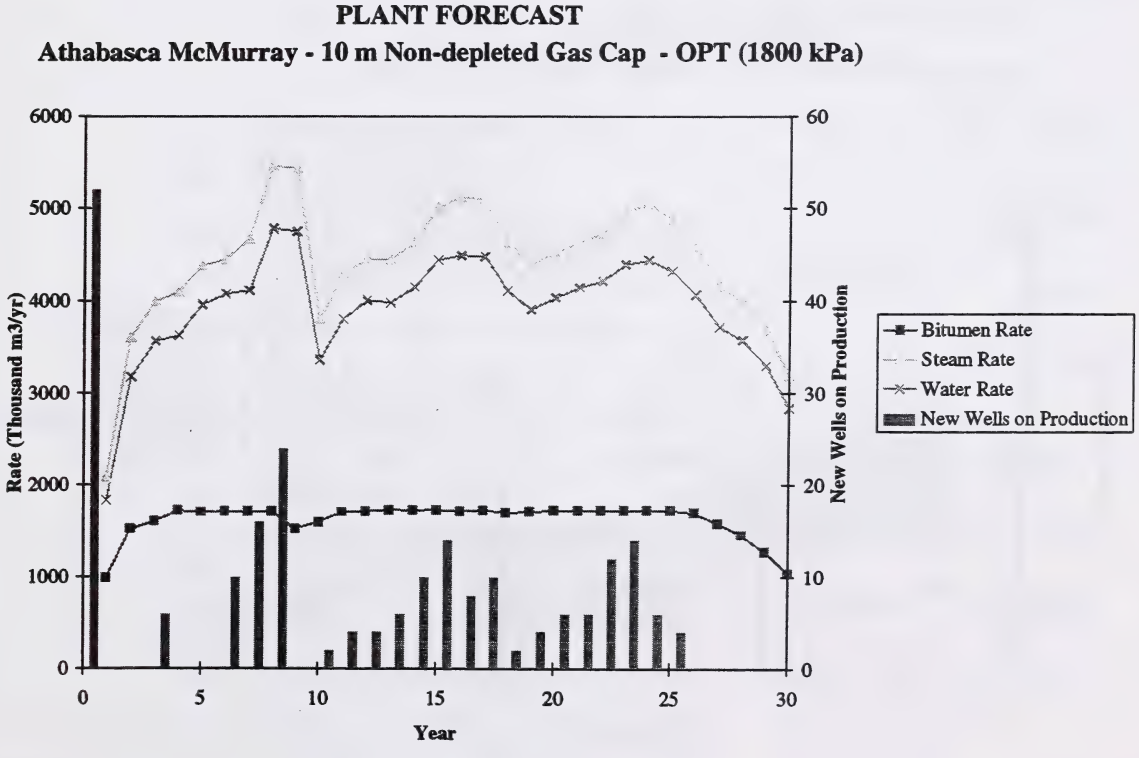


Figure 5.20

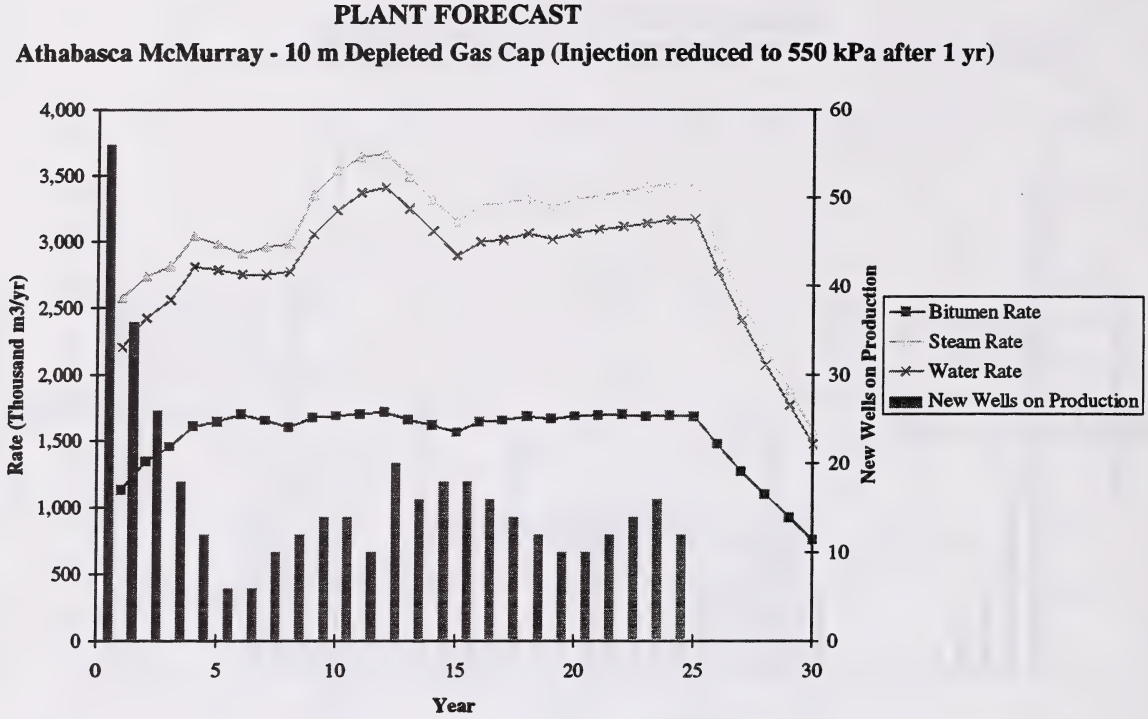

PLANT FORECAST
Athabasca McMurray - 10 m Depleted Gas Cap (Injection reduced to 550 kPa after 1 yr)
Rate (Thousand m3/yr)
New Wells on Production
Year
Bitumen Rate
Steam Rate
Water Rate
New Wells on Production

Figure 5.21

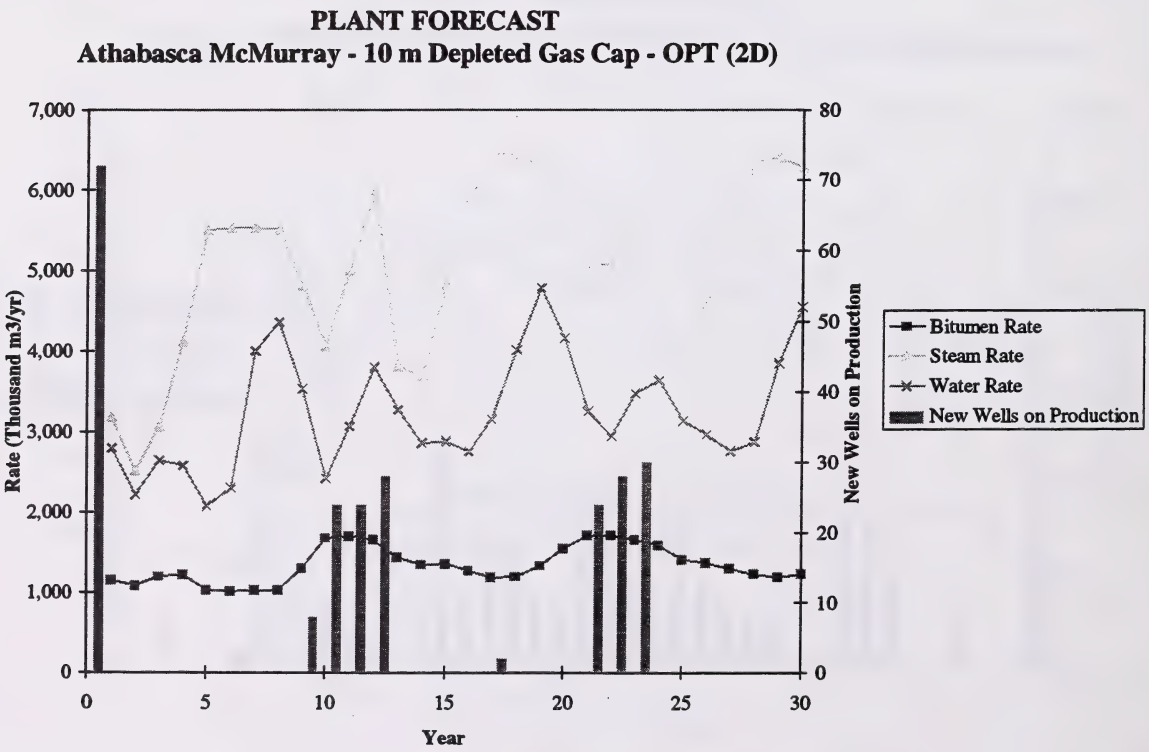


Figure 5.22

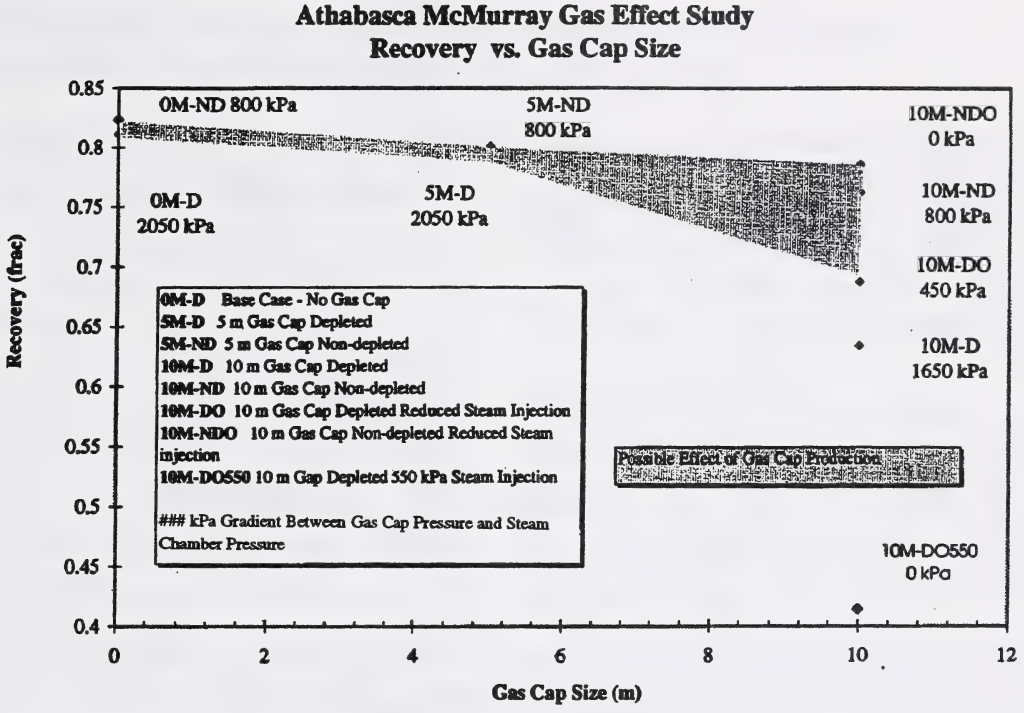


Figure 5.23

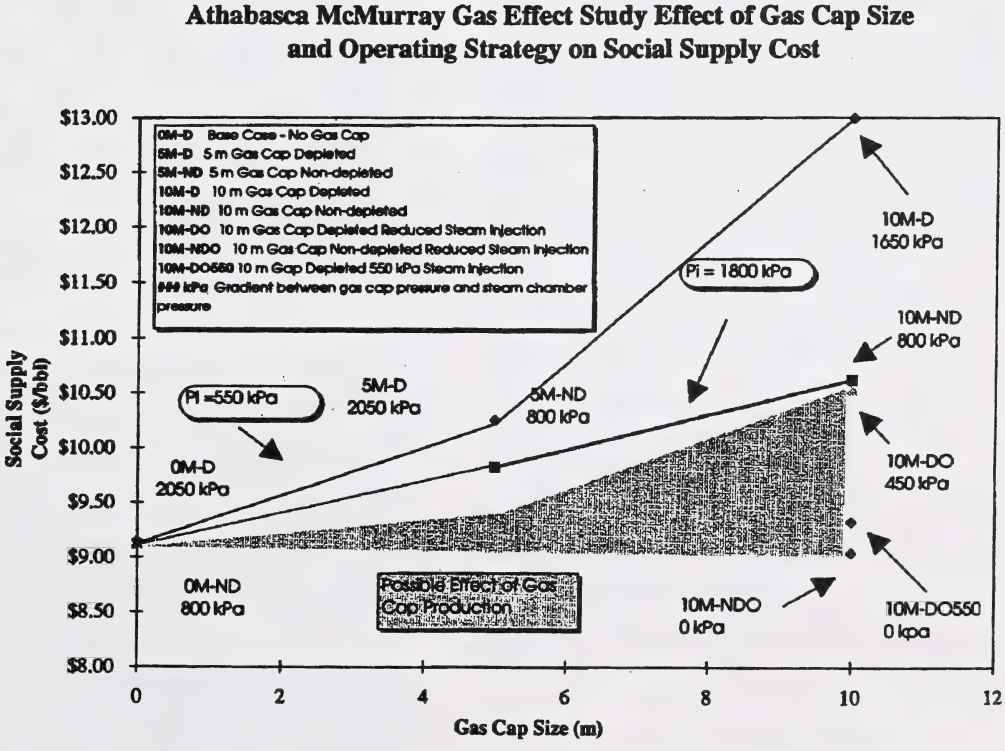


Figure 5.24

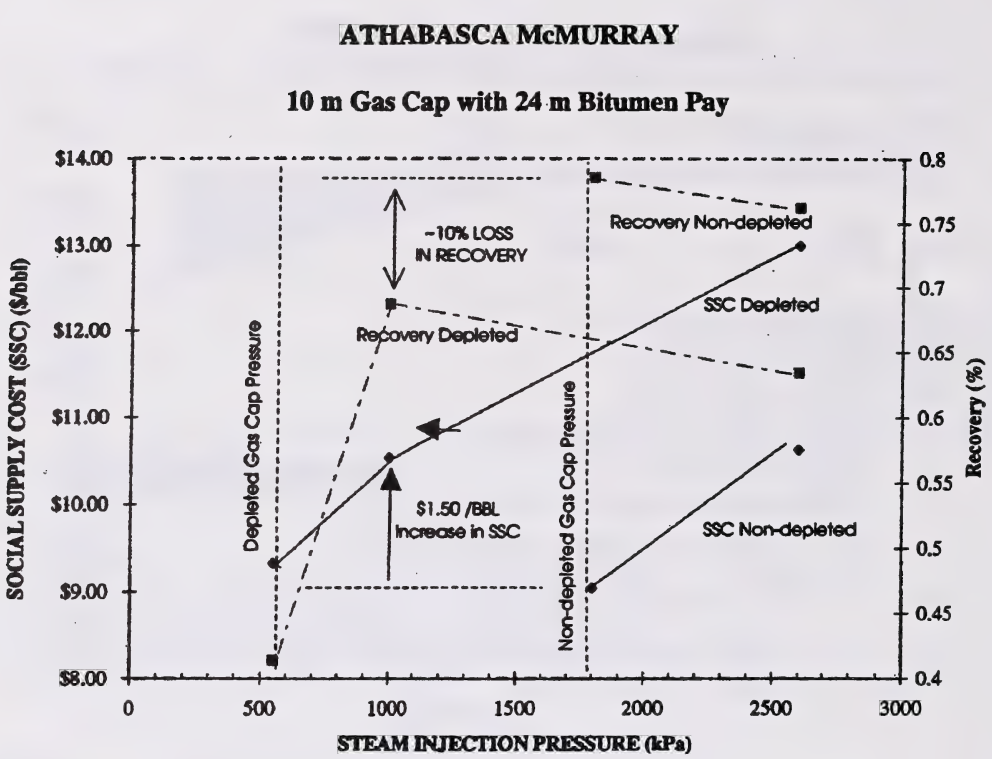


Figure 5.25 — Effect of Gas Cap Depletion on SAGD Performance

6.0 Effect of Gas Cap Depletion on SAGD Performance: Cold Lake Clearwater Formation, Wolf Lake

The purpose of this portion of the study is to provide an understanding of the effectiveness of the SAGD process in the Clearwater Formation at Wolf Lake with various associated gas cap thicknesses at different reservoir pressures. The reservoir pressures were varied to determine the effects of lower pressures resulting from gas production.

6.1 Geology

Wolf Lake is one of several fields within the Cold Lake area (Twp 61-68, Rges 2-6 W4M). The Wolf Lake field is the farthest west within the air weapons range and is located in Twp 66, Rge 6 W4M (Figure 2.1). The oil sands within the Cold Lake area are dispersed through four main stratigraphic intervals from approximately 295 to 600 m. In descending order, the predominant deposits are: the Upper and Lower Grand Rapids, the Clearwater, and the Wabiskaw/McMurray formations. A reference log is provided in Figure 6.1.

The main reservoir unit in the Clearwater sand, the C3 unit (as defined by the operator, Amoco Canada Petroleum Company), is between 9 and 25 m thick trending east to west across Amoco's oil sands lease. The sand has 45% oil saturation and 32% effective porosity. In the area of Amoco's proposed development, the C3 does not appear to have an associated gas cap. However, the C4/C5 units to the north do have a gas cap. The C4/C5 units are the result of a cut through the C3/C2/C1 units during a marine transgression. This valley is approximately 4 km wide and up to 75 m thick with local erosions into the Devonian. The C5 and C4 oil saturations and porosities are 45% and 33% and 55% and 33%, respectively. Calcite-cemented sands varying 1-3 m in thickness are present in the C2, C3, C4, and C5 but are not laterally extensive.

6.2 Bitumen Resource

The Cold Lake Clearwater Formation contains approximately 11 m^3 of bitumen in place according to the EUB's "Crude Bitumen Reserves Atlas" (May 1996). According to the atlas, the bitumen resource increases towards the southeast. However, two discrete accumulations are present in the western area of the deposit such that larger bitumen resources are concentrated in a north-south trend.

6.3 Well-Pair Performance Simulations

6.3.1 Model Selection

The application of SAGD technology in the Wolf Lake area has not previously been studied by the department. The reservoir characterization of the region was obtained from technical reports and well log and core data. The Clearwater Formation interval in the well, 10-31-66-5 W4M (the 10-31 well) was used to construct the model used for the Wolf Lake study. The 10-31 well is located in the northern part of Amoco's Wolf Lake oil sands lease and contains as much as 6.7 m of associated gas in the C1/C4 unit. The 10-31 well was evaluated by the EUB as being part of the Leming Upper Mannville O Pool. The bitumen zone is approximately 70 m thick.

6.3.2 Model Description

The simulation model for the Wolf Lake Clearwater Formation is similar to the multi-well pair model used in the Athabasca study. The model contains 2.5 well pairs but with 1000 m horizontal lengths spaced 90 m apart. The vertical distance between injector and producer is 6 m. The depth to the top of the formation is 420 m and the fracture pressure is approximately 8400 kPa.

The Wolf Lake model is 1490 m x 1000 m x 72 m (base case) and was modelled by a 2D Cartesian grid with the dimensions 145 x 1 x 36. Petrophysical properties are given in Table 6.1. Porosity varies from 28% to 30% with the exception of three sections of thin, tight carbonates that streak laterally. Permeability is relatively good, ranging from 2 Darcies at the base to 8.5 Darcies near the top of the oil sand. The lower third of the oil sand, below the lower carbonate streak, has poorer reservoir properties than the upper two-thirds. Therefore, the well pairs were located approximately 20 m from the base of the zone, reducing the net pay above the producers to approximately 50 m. The upper two streaks are above the injectors and are within 30 m of the reservoir top. The streaks were modelled by laterally alternating 6 m of porous rock separated by 10 m of non-porous rock within the 90 m well pair spacing.

Based on the 10-31 well logs and data supplied by Amoco, the water saturation varies from 40% to 65%. The relative permeability curves were adjusted for each layer by setting the residual water saturation equal to the water saturation to prevent initial mobile water from breaking through to the gas cap.

The oil viscosity data were taken from the Burnt Lake study and were determined from Puttagunta's single-point correlation. The viscosity is less than that of the Athabasca bitumen by approximately a factor of 10.

The high-pressure (non-depleted) and low-pressure (depleted) cases were run at initial reservoir pressures of 2500 and 650 kPa, respectively, based on data for gas pools in the area. The high-pressure cases used "live oil" containing 5.7% CH_4 and the low-pressure cases used "dead oil."

The gas cap was modelled by adding 2 m grid blocks to obtain 4 m and 8 m gas caps. The gas cap consists of 80% CH_4 and 20% water.

6.3.3 Simulation Results

The following cases were modelled in this portion of the study:

Gas Cap Thickness (m)	High Pressure Non-depleted Reservoir (2500 kPa)	* Low Initial Depleted Reservoir (650 kPa)
0	✓	✓
4	✓	✓
8	✓	✓

All cases have approximately 52 m of bitumen above the producers.
* Denotes cases using reduced steam injection pressure and/or rate after 2 years from start up.

The results for each case, including bottomhole injection pressure and rates of steam injection, oil production, and water production are included in Appendix E. The results for each of the 2.5 well pairs (reported as 3 well pairs), summarized on an average well pair quarterly basis and used in the social supply cost analysis, are provided in Figures 6.2 to 6.7 and summarized in Table 6.2.

The non-depleted high-pressure cases operated at the gas cap pressure of 2500 kPa show rising steam rates and bitumen production rates for the first 6 years, at which time the steam chamber reaches the gas cap. In the no-gas-cap case, steam rates then decrease gradually while production continues to increase as the chamber expands laterally; then both steam rate and bitumen production begins dropping in the 9th year as the steam chambers in each pattern merge. The 4 m and 8 m thick gas cap cases show progressively increasing steam injection during the 6th to 9th years—possibly as a result of steam loss or interference with the gas cap. In general, the CDORs and CSORs are in the order of 90 m^3 per day and 3.3 to 3.6, respectively, with recoveries of about 58%.

Performance for depleted low-pressure cases operated at slightly above the 650-kPa gas cap pressure are somewhat different because of reduced operating pressure: 750 to 800 kPa compared to 2500 kPa. Production rates are lower than for the non-depleted cases at approximately 50 m^3 of bitumen per day with pattern lives in the order of 30 years. CSORs are higher, in the order of 3.9, but recovery is also marginally greater ranging from 58% for the 8 m gas cap case to 64% for the no-gas-cap case.

The depleted cases are more susceptible to steam losses due to a pressure gradient between the steam chamber and the surrounding reservoir (including gas cap) whereas the non-depleted cases, with no pressure gradient, are not subject to this effect.

6.4 Commercial Project

The commercial plant well drilling and tie-in schedule and resulting bitumen and water production and steam injection rates are summarized for each case in Figures 6.8 to 6.13. The number of well pairs required to maintain the plant at (or close to) capacity for the base case, 4 m, and 8 m gas cap cases are, respectively, 90, 92, and 94 for the non-depleted study and 80, 84, and 88 for the depleted study. As previously noted, the depleted cases have roughly twice the pattern life of the non-depleted cases due to the lower production rates. These longer well lifetimes, in the order of 30 years, raise some question about the ability to maintain well integrity for that period.

The detailed commercial plant forecast, including the major capital and operating costs, is provided in Appendix E. The costs are again presented for each case in undiscounted 1995 dollars on a yearly basis for the project life of 30 years.

6.5 Social Supply Cost

The social supply cost results for the six cases are provided in Table 6.2. The table gives major operating costs and capital costs and a production/injection summary and recovery for each case.

Social supply costs are relatively high, partly because of low oil saturation in the reservoir, and vary from $11.07 to $12.65 per barrel. The non-depleted cases have consistently lower social supply costs than their depleted counterparts. The greatest difference is for the base case which results in a $1.02 per barrel difference in social supply cost from depleted and non-depleted reservoir pressures. These results are somewhat idealized since the plant steam capacities in the depleted cases are all over-designed to maintain a high bitumen throughput in the plant. This difficulty stems from the scheduling of wells with different production profiles and pattern lives. The majority of the wells required in the depleted cases are on production early in the project and capital cost is therefore high at the beginning of the project. In the non-depleted cases, the capital cost is deferred for the additional wells and payout would occur sooner for the wells drilled due to higher production rates. For this reason, the discount factor has a strong impact on capital costs.

The low bottomhole pressures encountered in the depleted cases may not lift the fluids to the surface. Therefore, a means of artificial lift would likely be required to produce the fluids. The capital and operating costs of the

artificial lift system would add to the supply cost. These components have not been incorporated in this economic evaluation.

6.6 Clearwater Wolf Lake Gas Effects Summary

The bitumen recovery per well pair and social supply cost were used to assess the effect of associated gas pressure depletion on SAGD performance and are plotted in Figures 6.14 and 6.15 and summarized below.

The Wolf Lake Clearwater model is more complicated than the Athabasca McMurray model. A proven model is not available and descriptive reservoir data may require further scrutiny, particularly with respect to relative permeability. The presence of carbonate sections, lower horizontal permeability, and high water saturations are detrimental to the SAGD process. These characteristics are reflected in high social supply costs.

Bitumen recoveries plotted in Figure 6.14 show that ultimate recoveries are similar at approximately 58% for the non-depleted gas cap cases. Recoveries for the depleted gas cap cases are, however, higher than for the non-depleted cases and decrease from 64% for the base case to 58% for an 8 m gas cap. These results are unexpected based on the Athabasca results and may be attributed to solution gas effects present in the Wolf Lake bitumen but not in Athabasca bitumen.

Discounted social supply costs plotted on Figure 6.15 show that, in all cases, bitumen associated with depleted gas caps costs more to produce than that associated with non-depleted gas caps. Incremental costs are $1.02, $0.03, and $0.18 per barrel of bitumen for the 0 m, 4 m, and 8 m gas caps, respectively.

In summary, the relatively small differences in social supply costs for the cases, offset by some improvement in bitumen recovery, suggest that depletion of the gas cap may not be as detrimental to SAGD performance as in Athabasca McMurray. This result is qualified by uncertainty about the overall effect of solution gas, the accuracy of the model in representing the Clearwater Wolf Lake reservoir, and other operational factors including optimal injection rates and development of artificial lift techniques.

Gas Cap Thickness (m)	Initial Reservoir Pressure (kPa)	Steam Chamber Pressure (kPa)	Social Supply Cost ($/bbl)	Recovery (%)	CDOR (m^3/d)	Cum. SOR (m^3/m^3)
0	650	750*	12.65	64.3	52	3.89
0	2500	2500	11.63	57.7	93	3.55
4	650	775*	11.56	61.6	51	3.93
4	2500	2500	11.53	59.2	91	3.49
8	650	800*	11.25	58.4	52	3.86
8	2500	2500	11.07	58.5	93	3.29

Note: There are slight rounding errors associated with the above quotes.
* Denotes average pressure over well operating life.

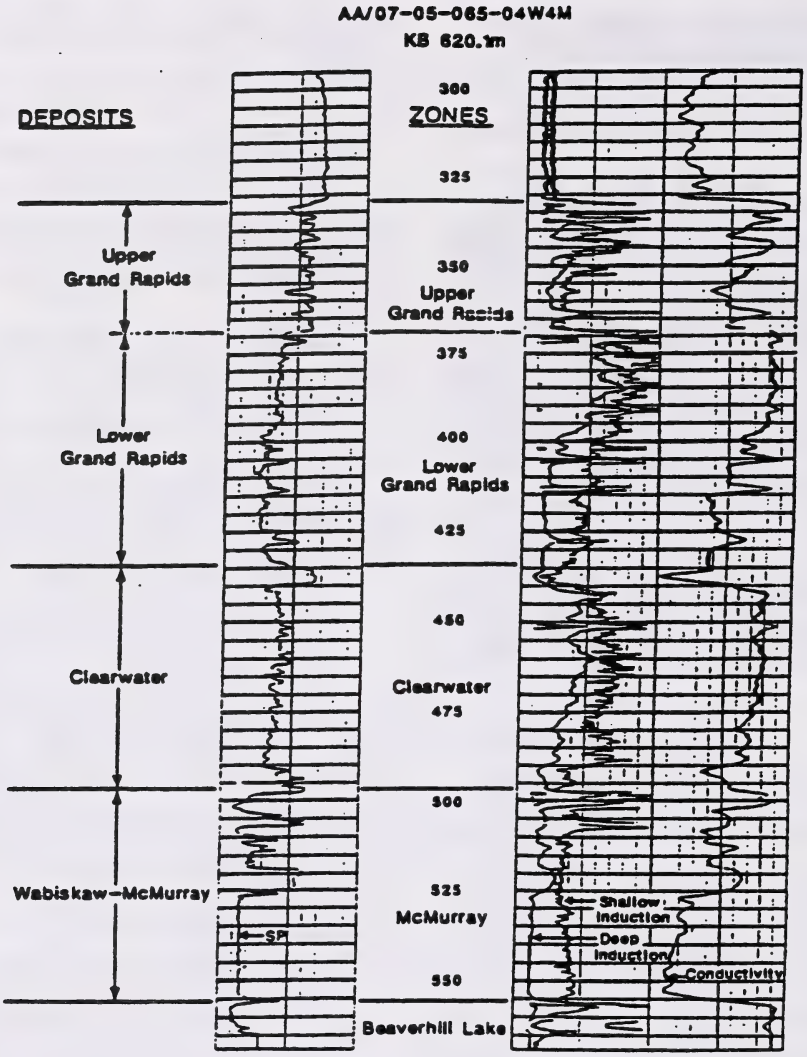


Figure 6.1 — Cold Lake Oil Sands Area Reference Well
Esso Cold Lake OV 7-5-65-4W4M

WOLF LAKE CLEARWATER FORMATION
RESERVOIR PARAMETERS FOR 2D MODEL

GRID NO.	POROSITY (PHI)	WATER SATURATION (Sw)	Oil Saturation (So)	Ki=Kj	Kk
36	0.24	0.60	0.40	400	400
33-35	0.30	0.50	0.50	8000	2400
32*	0.30	0.50	0.50	8500	2400
29-31	0.30	0.60	0.40	8500	2550
28*	0.30	0.60	0.40	8500	2550
21-27	0.28	0.55	0.45	3600	1080
16-20	0.30	0.65	0.35	4000	1200
15	0.30	0.40	0.60	3300	990
14	0.30	0.65	0.35	3300	990
Injector 12-13	0.30	0.40	0.60	3300	990
11	0.30	0.40	0.60	2000	600
Producer 10 *	0.30	0.40	0.60	3300	600
7-9	0.30	0.50	0.50	2000	600
1-6	0.30	0.40	0.60	650	195

* Tight carbonate streaks alternating with porous rock.
2m grid blocks in the k direction.

Table 6.1

Wolf Lake Clearwater Gas Effect Study
Supply Cost Summary
Discounted @10% to 1995 Dollars

	0m Gas Cap Depleted	0m Gas Cap Nondepleted	4m Gas Cap Depleted	4m Gas Cap Nondepleted	8m Gas Cap Depleted	8m Gas Cap Nondepleted
Cost Centre	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**
Capital Cost						
Drilling	$15.44	$8.53	$15.06	$8.52	$12.98	$8.40
Seism/Delin/Eng	$0.40	$0.43	$0.56	$0.40	$0.39	$0.38
Steam Facilities	$7.81	$8.11	$16.79	$7.43	$6.32	$6.75
Other Facilities	$15.86	$17.29	$22.51	$15.77	$15.46	$15.13
Total Capital	$39.51	$34.36	$54.92	$32.11	$35.15	$30.65
Operating Cost						
Gas Cost	$27.49	$20.81	$25.33	$20.45	$22.89	$19.54
Utilities	$7.35	$5.58	$6.76	$5.48	$6.13	$5.23
Production Treating	$0.81	$0.83	$0.88	$0.81	$0.81	$0.80
Water Treating	$2.38	$1.79	$2.24	$1.77	$2.15	$1.70
Fixed and Other	$8.61	$9.39	$12.22	$8.56	$8.39	$8.21
Total Operating Cost	$46.65	$38.40	$47.43	$37.07	$40.37	$35.49
Total Cost/m3 BIT	$86.16	$72.76	$102.35	$69.18	$75.52	$66.15
Total Cost/bbl BIT	$13.70	$11.57	$16.27	$11.00	$12.01	$10.52
Plant Summary						
Number of Wells	174	80	102	90	152	92
Cum Bitumen Produced (E3m3)	38,666	38,713	26,657	43,337	40,967	44,580
Cum Steam Injected (E3m3)	182,708	137,701	122,808	151,916	158,946	148,510
Cum Water Produced (E3m3)	188,856	141,665	120,761	157,309	175,291	154,183
Plant CDOR (m3/d)	3,531	3,535	2,434	3,958	3,741	4,071
Plant CSOR (m3/m3)	4.73	3.56	4.61	3.51	3.88	3.33
Bitumen Capacity Utilization	74.0%	74.1%	51.0%	83.0%	78.4%	85.4%
Steam Capacity Utilization	61.9%	46.6%	41.6%	51.4%	53.8%	50.3%
Avg. Well Summary						
Pattern Life (yrs.)	14	14	14	14	14	14
Cum Bitumen Produced (E3m3)	225	496	261	501	238	502
Cum Steam Injected (E3m3)	1,039	1,737	747	1,722	747	1,636
Cum Water Produced (E3m3)	1,096	1,822	870	1,818	872	1,732
Well CDOR (m3/d)	44	97	51	98	54	98
Well CSOR (m3/m3)	4.62	3.5	2.86	3.44	2.73	3.26
Recovery (90m spacing)	25.5%	56.2%	29.6%	56.8%	31.1%	56.9%

Table 6.2

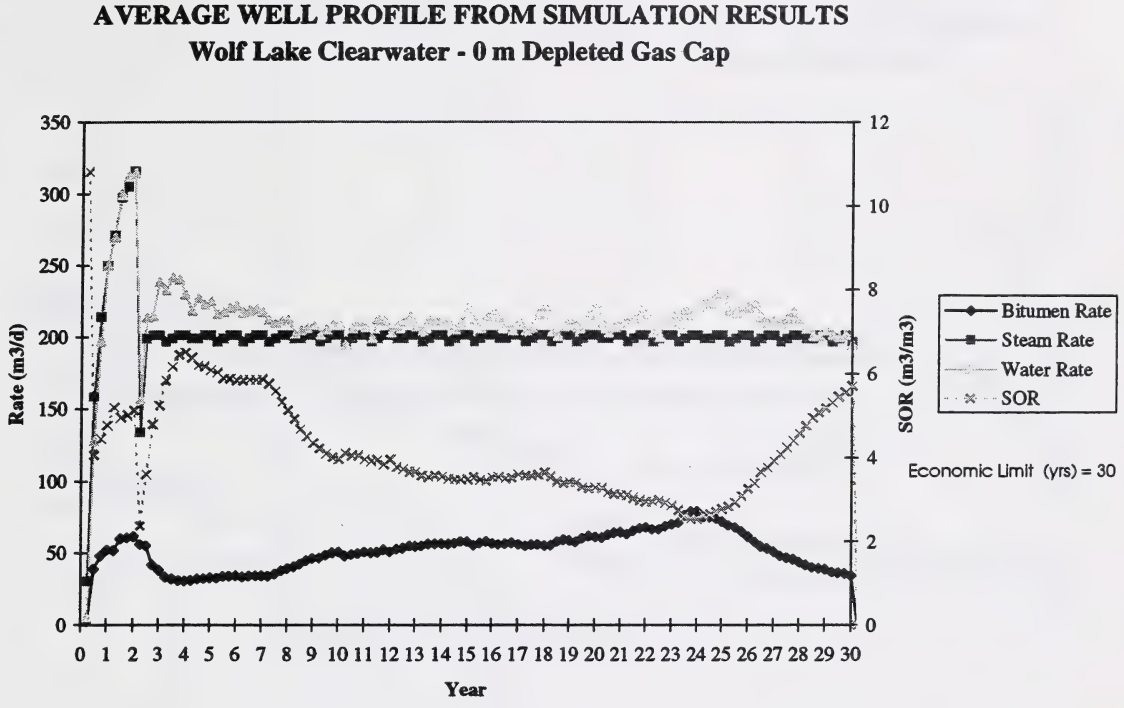


Figure 6.2

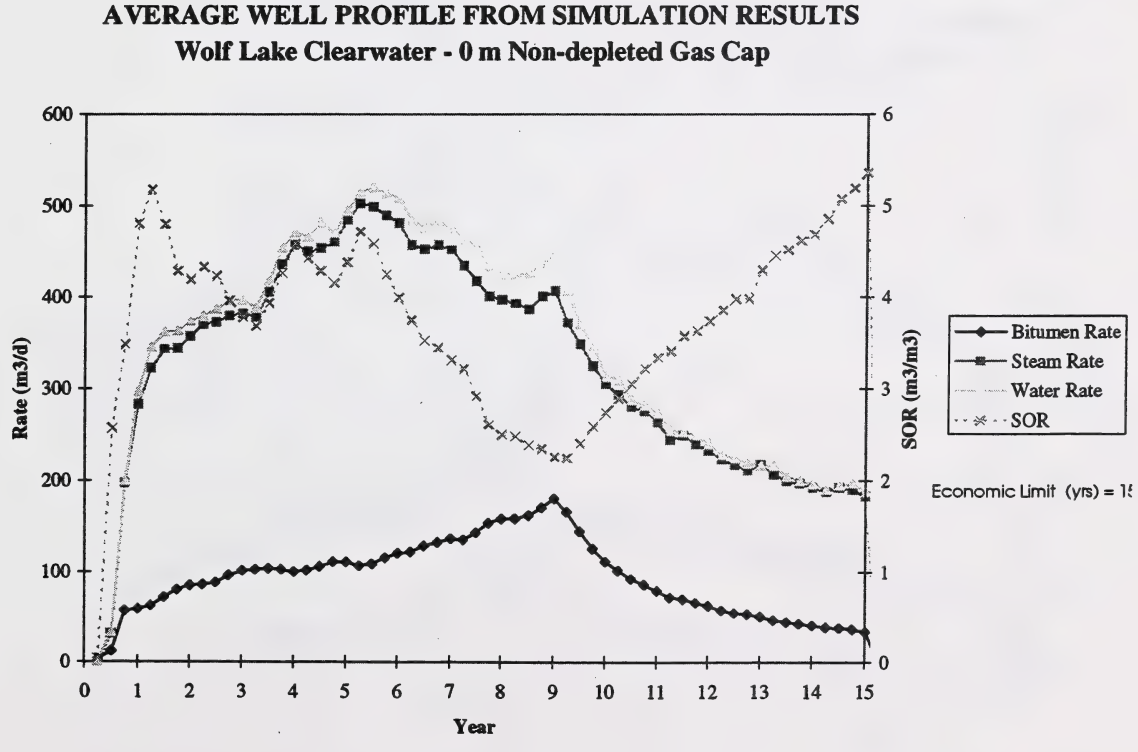


Figure 6.3

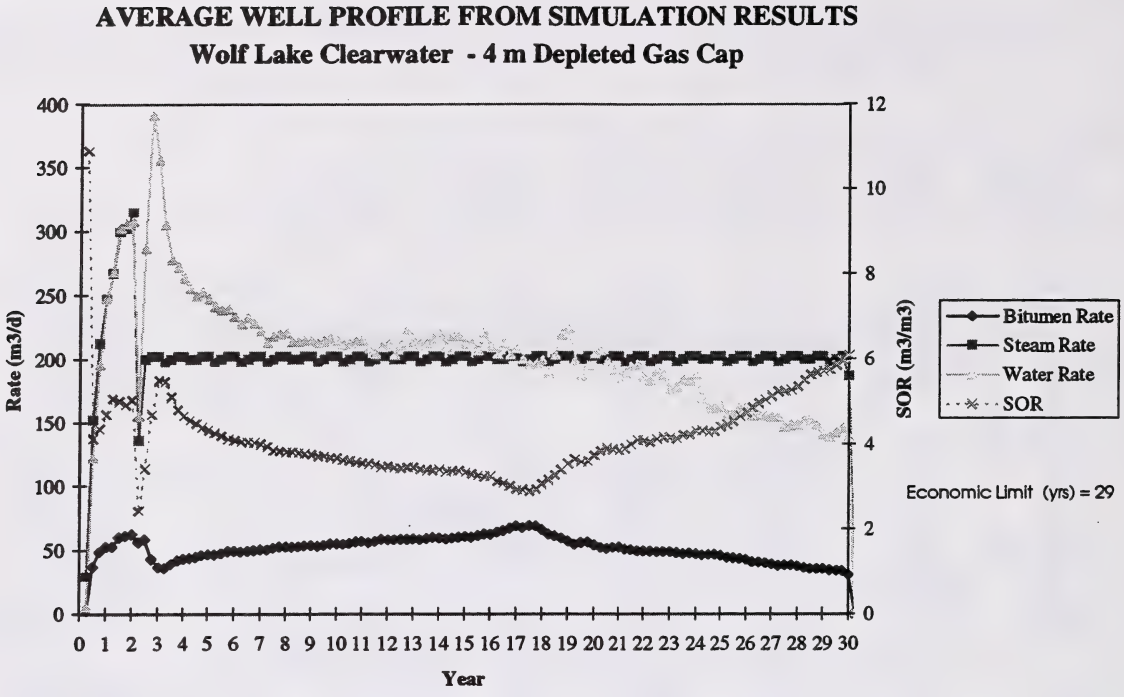


Figure 6.4

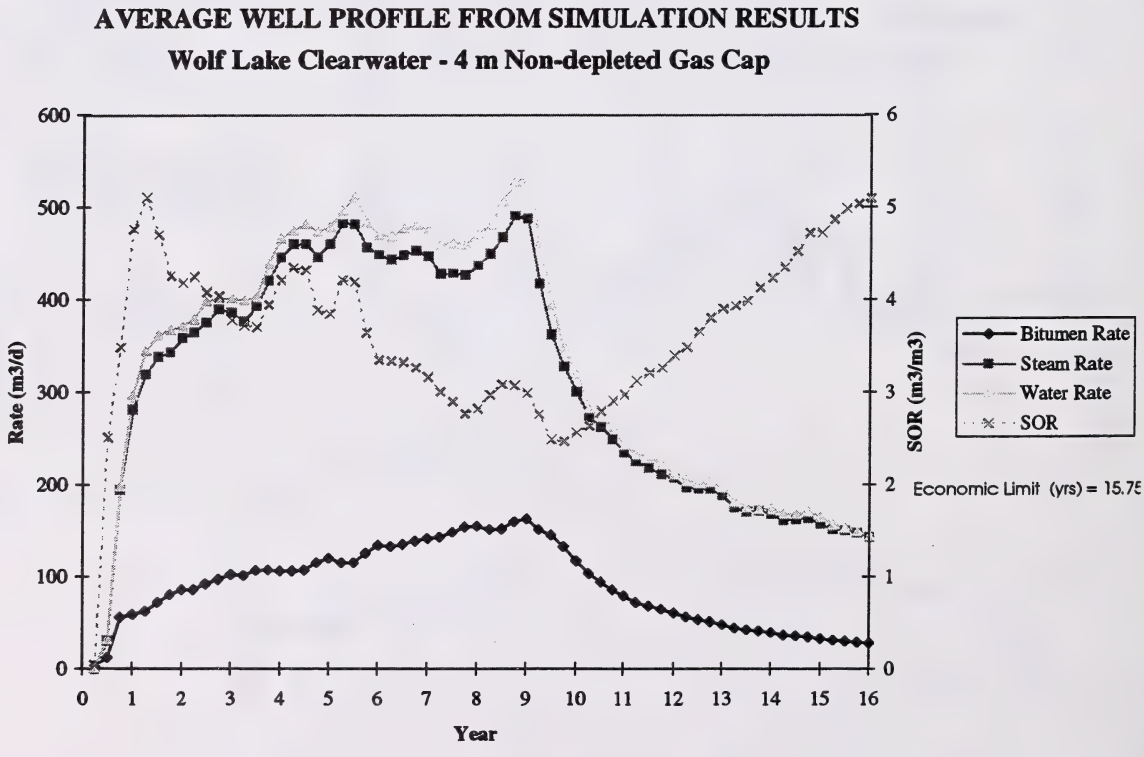


Figure 6.5

AVERAGE WELL PROFILE FROM SIMULATION RESULTS
Wolf Lake Clearwater - 8 m Depleted Gas Cap

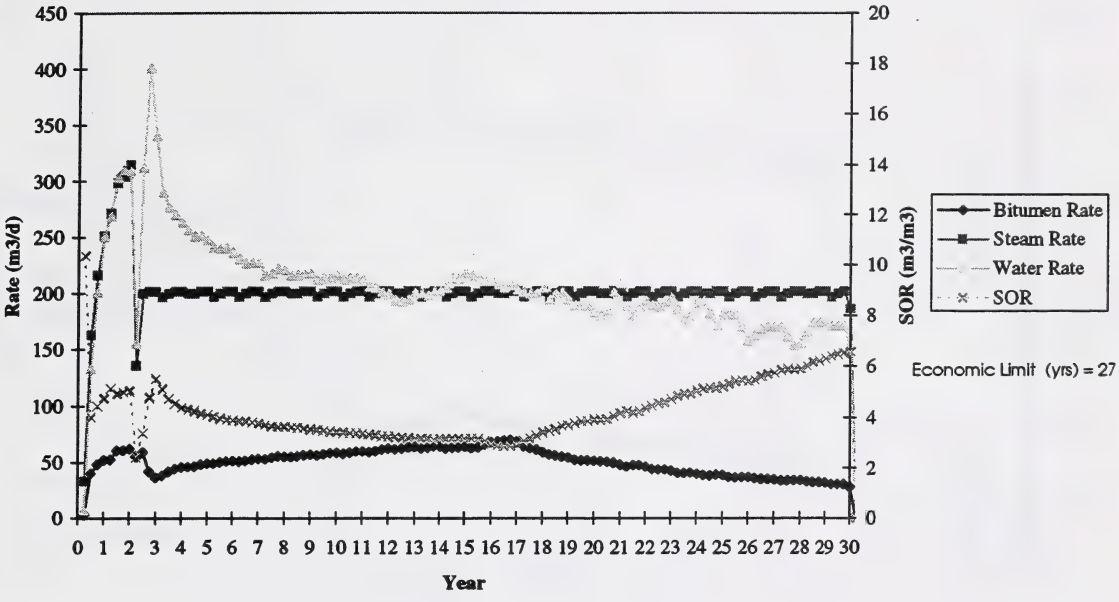


Figure 6.6

AVERAGE WELL PROFILE FROM SIMULATION RESULTS
Wolf Lake Clearwater - 8 m Non-depleted Gas Cap

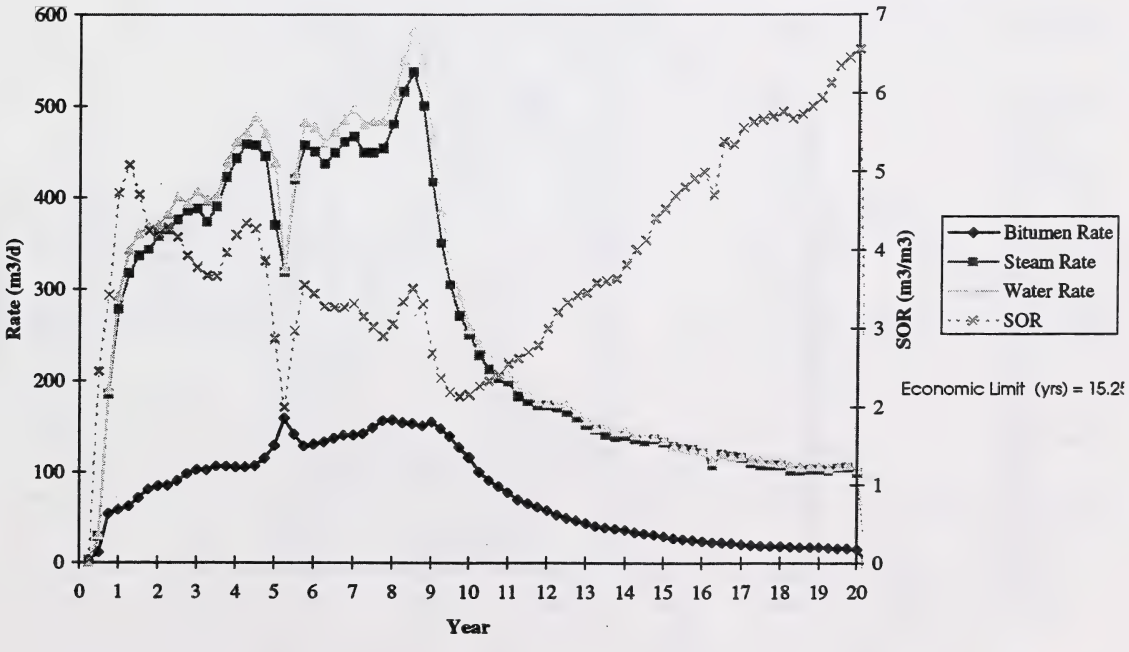


Figure 6.7

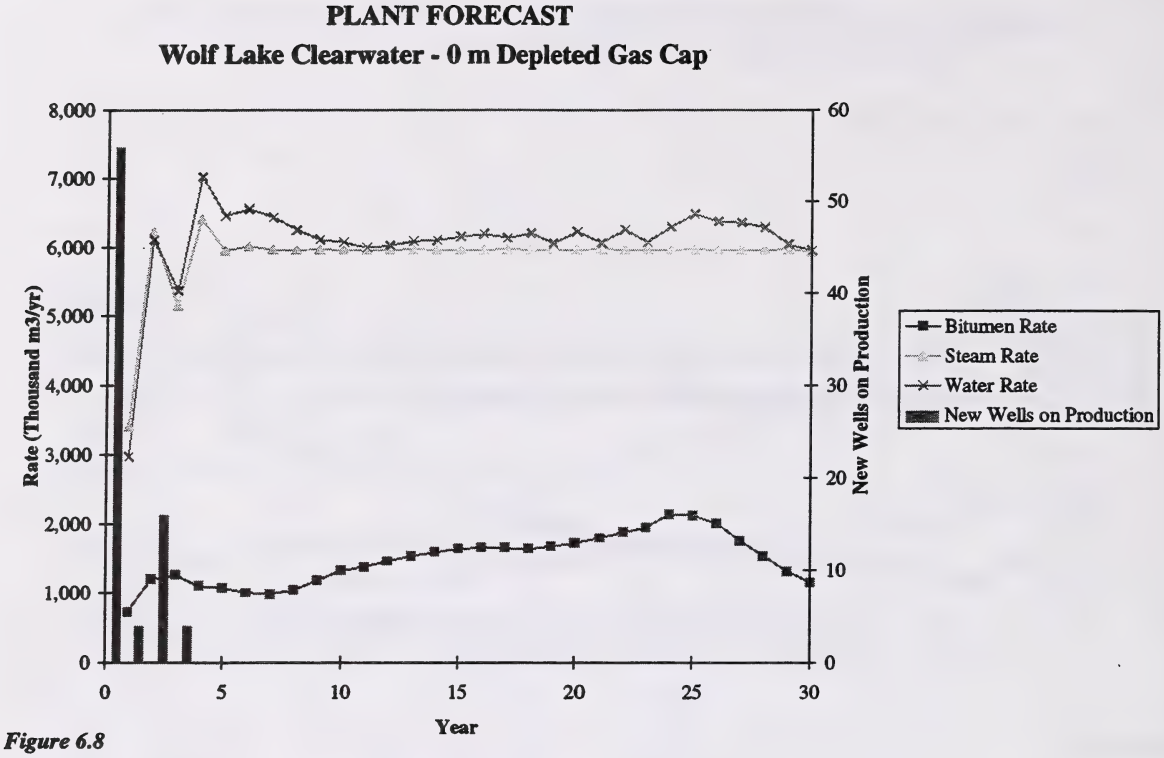


Figure 6.8

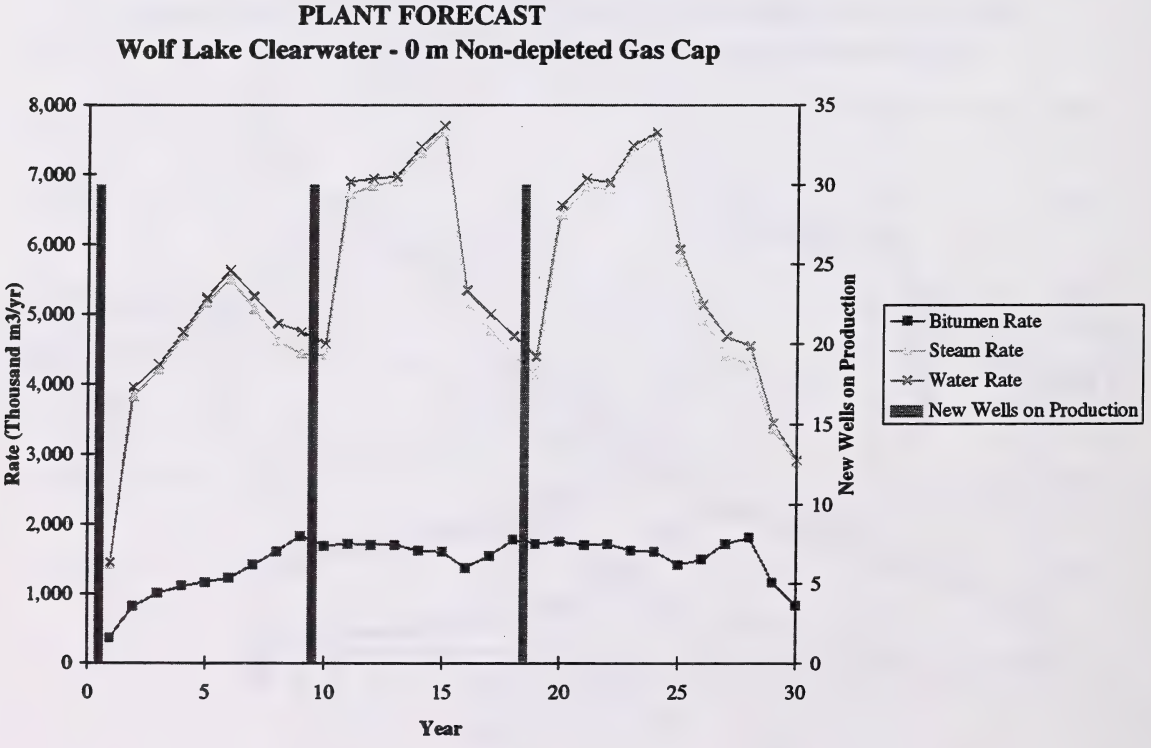


Figure 6.9

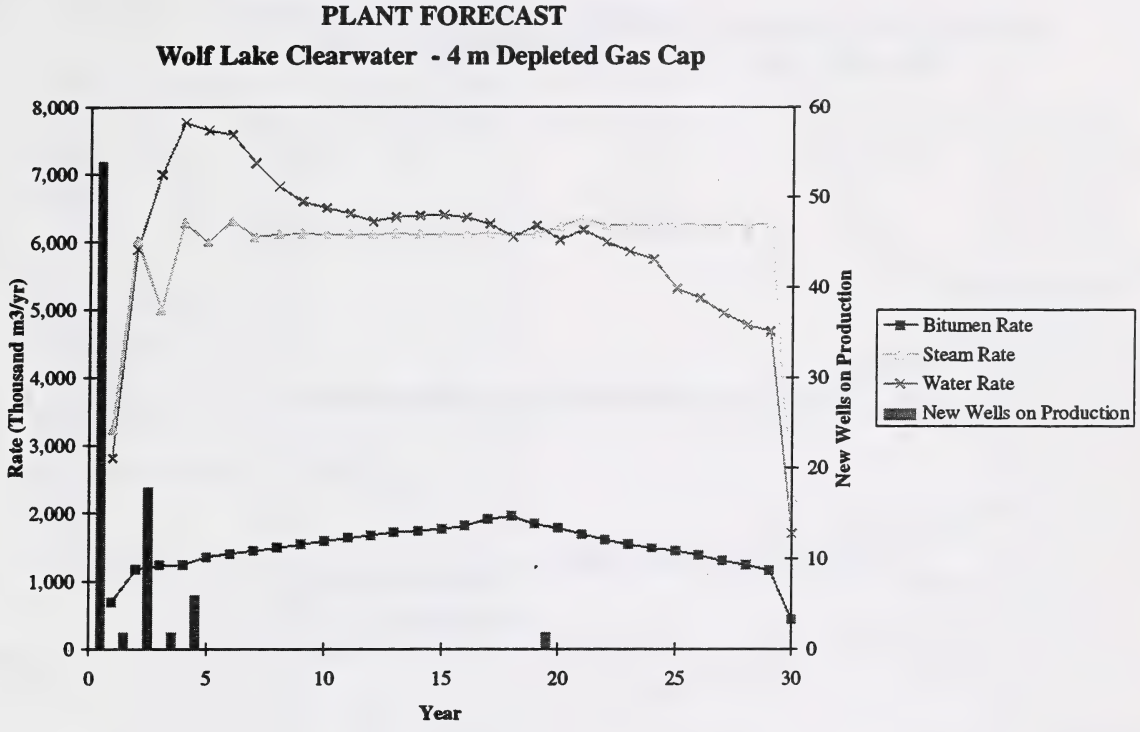


Figure 6.10

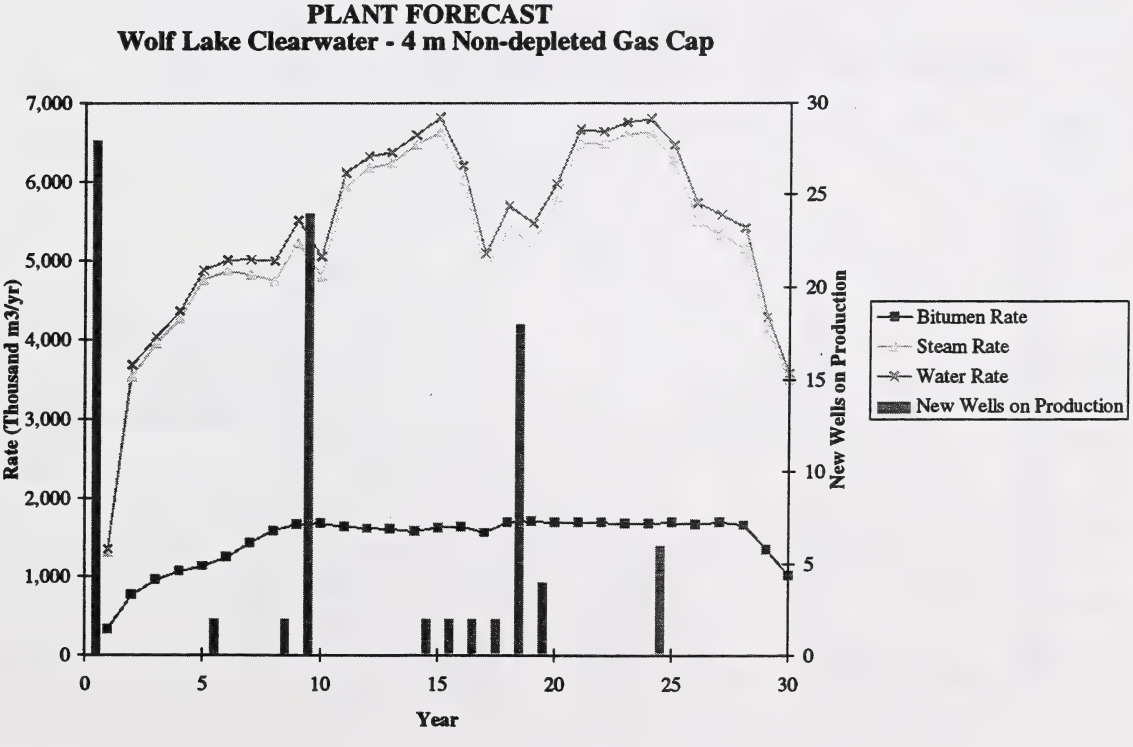


Figure 6.11

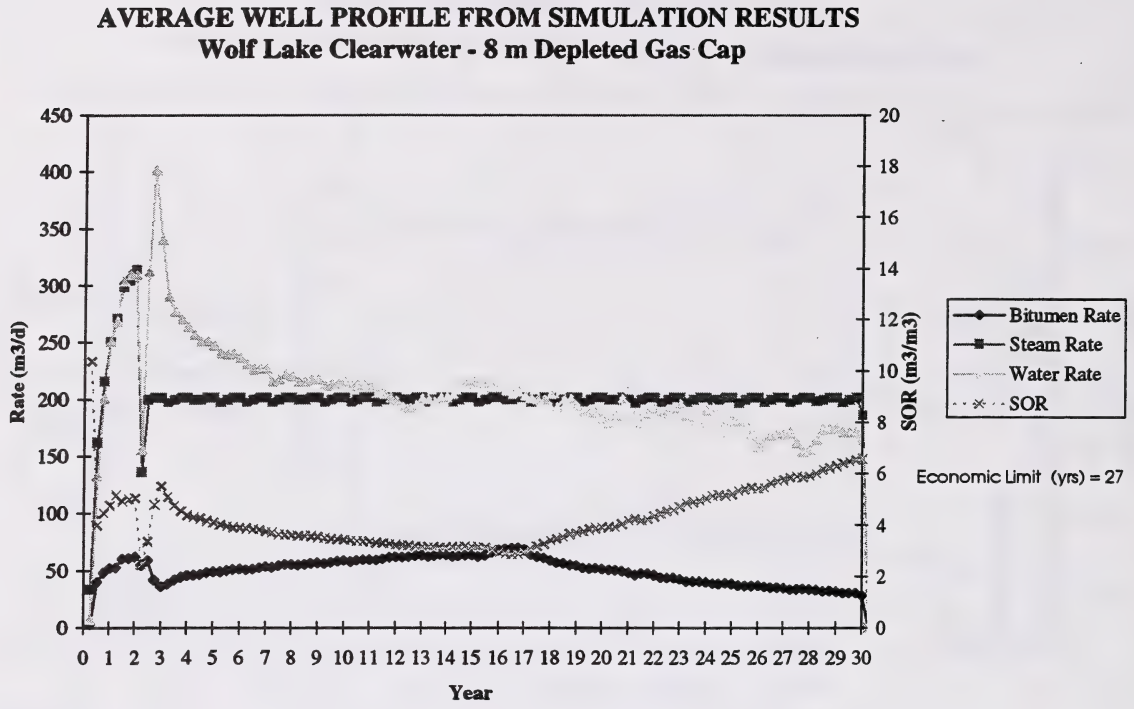


Figure 6.12

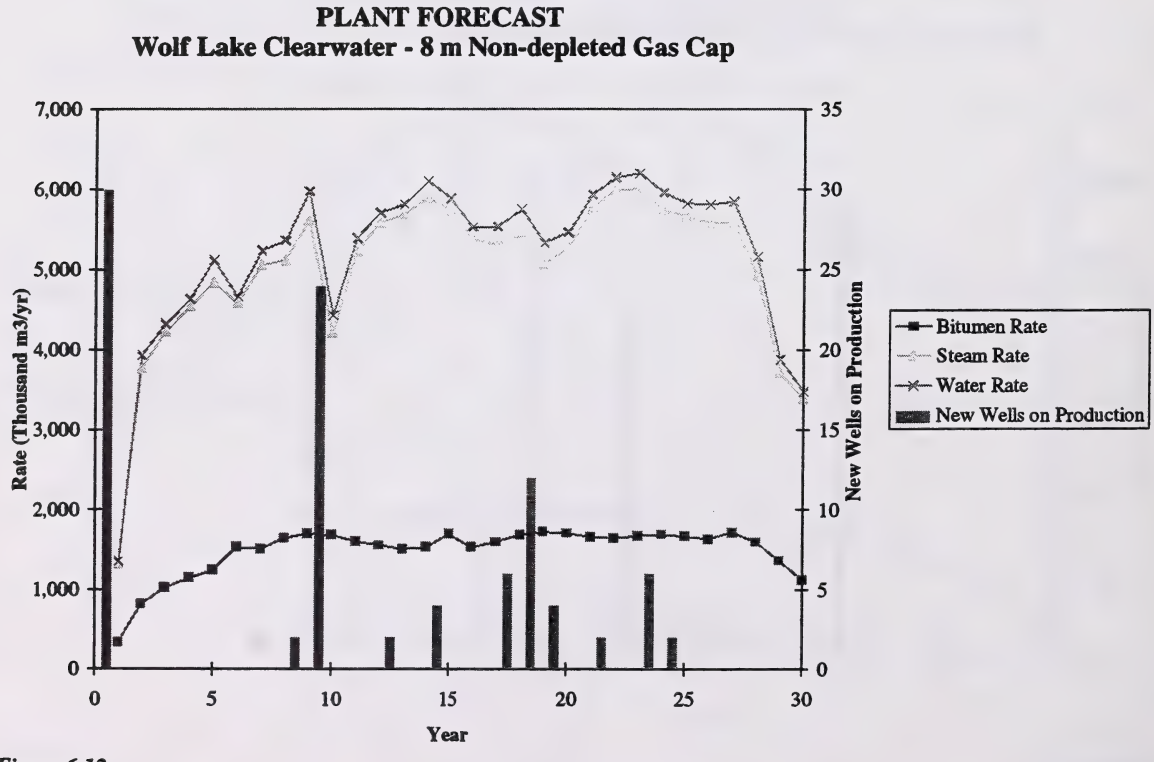


Figure 6.13

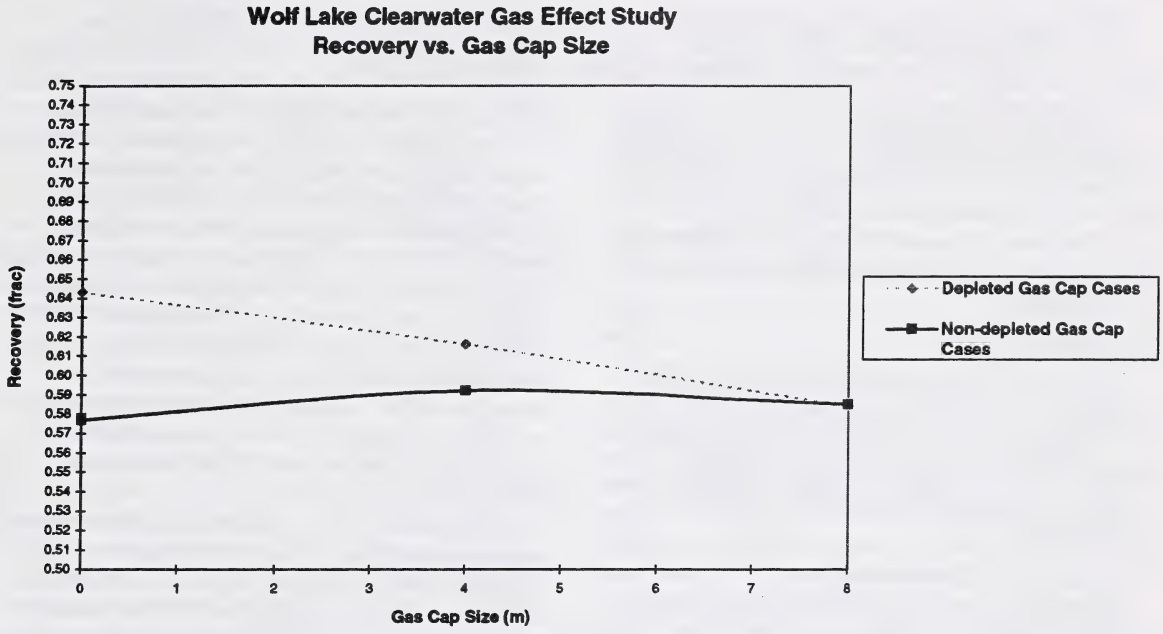


Figure 6.14

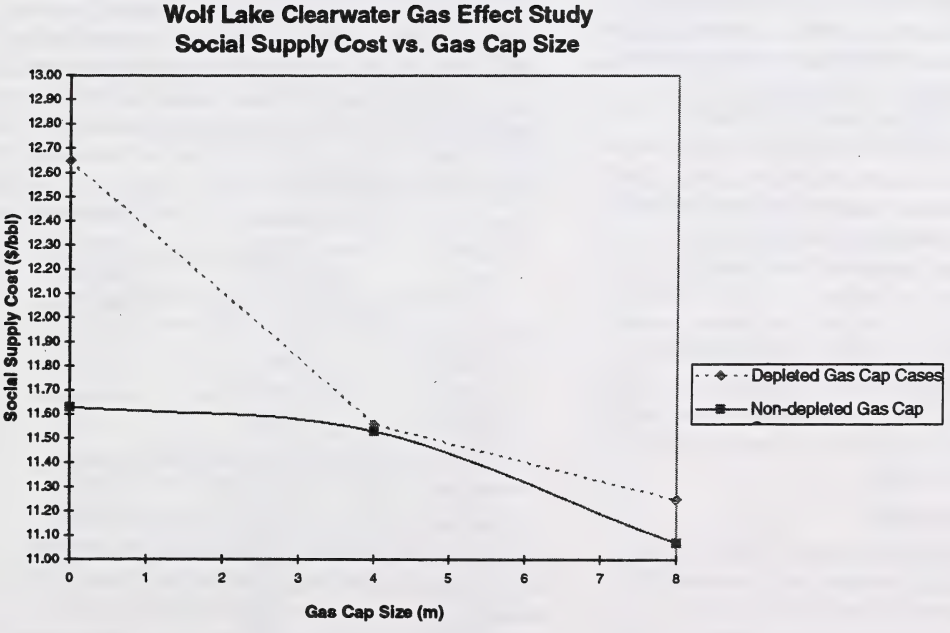


Figure 6.15

7.0 Effect of Gas Cap Depletion on SAGD Performance: Cold Lake Clearwater Formation, Burnt Lake

The intent of this portion of the study is to provide an understanding of the effectiveness of the SAGD process in the Clearwater Formation at Burnt Lake with various associated gas cap thicknesses at different reservoir pressures. The reservoir pressures were varied to determine the effect in each model of lower reservoir pressure as a result of gas production.

7.1 Geology

A reference log describing the Cold Lake Clearwater Formation in the Burnt Lake area (Twp 67&68, Rge 3 W4M) is given in Figure 7.1. The bitumen-bearing zone, the Clearwater B sand, is approximately 20-30 m thick, overlain, and capped with 3-5 m of shale. The sand is unconsolidated.

7.2 Bitumen Resource

Please refer to Section 6.2 of this report for a brief description of the Cold Lake resources.

7.3 Well-Pair Performance Simulations

7.3.1 Model Selection

The Burnt Lake model was initially based on core and log data from two wells (00/06-15-065-04W4/0 and AA/07-36-065-04W4/0). The model consisted of high-permeability (7 to 10 Darcies) regions in the lower and middle sections. The upper layers contained low-permeability (1.2 to 3 Darcies) sections. A literature search was conducted on numerical simulation studies involving the Clearwater Formation to verify petrophysical properties. The results of the review indicated that the permeability (both horizontal and vertical) was in all likelihood too high for the Clearwater Formation. The model selected was from the technical paper, "Numerical Study of the SAGD Process in the Burnt Lake Oil Sands Lease" by Ken Kisman (formerly of the Department of Energy) and K.C. Yeung of Suncor. The Burnt Lake model was adjusted from a half-well pair to a multi-well pair model based on experience in adapting the UTF model for studying gas effects, and was modified by adding 5 m and 10 m gas caps.

7.3.2 Model Description

The Burnt Lake model description is shown in Figure 7.1. The model was adjusted slightly to conform with the multi-well pair pattern model used in the Athabasca McMurray Formation study. The initial reservoir pressure given in the Burnt Lake technical paper of 3100 kPa was also used. The petrophysical properties, including porosity, fluid saturations, and permeability are poor in the lower 6 m of the reservoir. The producing wells are therefore located 7 m above the reservoir base and the injectors are 6 m above the producers. Tight carbonate layers are present in the Clearwater Formation in the Burnt Lake and Wolf Lake areas according to drilling records, but are not laterally extensive. At Burnt Lake, a tight carbonate layer is located about 24 m above the base of the Clearwater and is modelled by porous and non-porous streaks. The lateral dimensions of the streaks are 6 m of porous material followed by 10 m of non-porous rock within the well spacing area and 10 m porous followed by 15 m non-porous outside the well spacing area. The inside and outside well pairs are directly below non-porous streaks and the middle well pair is directly below a porous streak.

For this model, a high-pressure (non-depleted) reservoir with an associated gas cap is subject to a pressure of 3100 kPa. The low-pressure (depleted) reservoir with an associated gas cap is subject to a pressure of 600 kPa. Similar to Wolf Lake, the high-pressure cases were designed using a live oil containing 14% solution gas. The low-pressure cases were designed using a dead oil. Steam was injected at 8000 kPa, below the fracture pressure of 9000 kPa, until the production well could maintain flow to surface. The injection pressure was lowered after 80 days to 3000 kPa (100 kPa below initial reservoir pressure) and the production wells were placed on SAGD production control with a maximum steam rate of 0.5 m^3/d. The injection wells were each steam-rate-limited to 400 m^3/d, while the production wells were limited to total liquid withdrawals of 800 m^3/d.

7.3.3 Simulation Results

Gas Cap Thickness (m)	High Pressure* Non-depleted Reservoir (3100 kPa) (Live Oil)	Low Initial Depleted (600 kPa) (Dead Oil)
0	✓	✓*
5	✓	✓
10	✓	✓

All cases have approximately 26 m bitumen above the producers.

* Denotes cases in which a dead oil and live oil were investigated.

The results of each case showing the bottomhole injection pressure and rates of steam injection, oil production, and water production are included in Appendix F. The results for each of the 2.5 well pairs (reported as 3 well pairs), summarized on an average well pair quarterly basis are provided in Figures 7.2 to 7.8 and summarized in Table 7.2.

In comparing depleted cases with their non-depleted counterparts, it is observed that considerably more steam is injected in the depleted cases than in the non-depleted cases. Steam chamber pressures are greater than gas cap pressures, resulting in significant steam leak-off to the gas cap.

Steam/oil ratios decrease with increasing gas cap thicknesses for non-depleted cases as in the Wolf Lake simulation. This is thought to be due to the thermal insulating effects of the gas cap. The ratios increase significantly due to steam loss in the depleted cases. Recoveries appear to be 5% to 6% higher in the 0 m and 5 m depleted cases than in the corresponding non-depleted cases. The 10 m depleted gas cap exhibits a weaker recovery than the non-depleted case due to higher steam losses.

In all the depleted cases, the lower steam chamber pressures do not cause a decrease in bitumen production rates as experienced in McMurray and in Clearwater at Wolf Lake. Although the Clearwater at Burnt Lake had a low depleted reservoir pressure of 600 kPa, similar to Wolf Lake, the steam chamber pressures were higher at 2800 kPa, 1000 kPa, and 1300 kPa for the 0 m, 5 m, and 10 m gas cap cases, respectively. These larger pressure differentials compared to 100-150 kPa for Wolf Lake are believed to enhance the movement of steam into the bitumen, particularly in the lower-viscosity Cold Lake Clearwater bitumen, and improve production rates.

Bitumen production rates for the non-depleted gas cap cases are lower than for the depleted gas cap cases, even though the reservoir and steam chamber pressures are much higher. Although depleted gas cap bitumen production rates are believed to be enhanced, the higher-pressure non-depleted bitumen rates appear to be lower than expected. This performance is also different from Wolf Lake. Solution gas effects combined with different reservoir properties may contribute to this anomalous performance.

7.4 Commercial Project

The commercial plant well drilling schedule and resulting bitumen and water production and steam injection rates are summarized for each case in Figures 7.9 to 7.15. The number of well pairs required to maintain the plant at (or near) capacity for the base case and the 5 m and 10 m gas cap cases are, respectively, 122, 128, and 128 for the non-depleted cases and 108 (112 for the live oil case), 118, and 152 for the depleted cases.

7.5 Social Supply Cost

The social supply cost results for the seven cases, including major operating costs, capital costs as well as production and injection volumes and bitumen recovery for each case, are provided in Table 7.2 and Appendix F. Social supply costs discounted at 10% range from $8.24 per barrel of bitumen for the non-depleted 10 m gas cap to $12.70 per barrel of bitumen for the depleted 10 m gas cap which incurs considerable steam loss to the gas cap. The effect of steam loss to the gas cap is quite evident in the plot of social supply cost as a function of gas cap thickness in Figure 7.17. In the non-depleted cases, where the steam chamber and gas cap pressures are the same, the social supply cost decreases slightly with increasing gas cap thickness. This is attributed to the insulating effect of the gas cap. In the depleted cases, pressure differentials between the steam chamber and the gas cap of approximately 400 and 700 kPa for the 5 m and 10 m gas caps, respectively, increase the social supply cost from $11.19 to $12.70/bbl due to steam loss. The resulting social supply costs increase. Dead oil and live oil compared in the depleted 0 m gas cap case result in very similar social supply costs of $9.27 and $9.19/bbl, respectively.

7.6 Clearwater Burnt Lake Gas Effects Summary and Conclusions

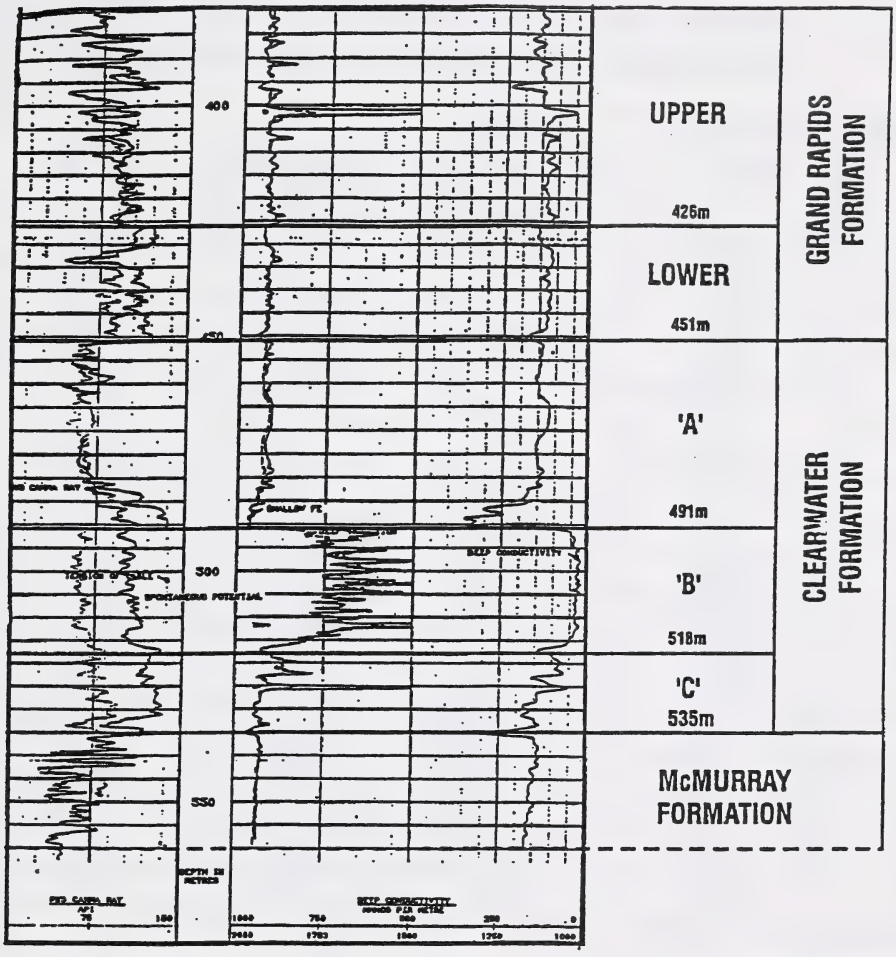
Bitumen recovery per well pair and social supply costs were used to assess the effect of associated gas pressure depletion and are plotted in relation to gas cap thickness in Figures 7.16 and 7.17. These criteria and others are summarized below.

Gas Cap Thickness (m)	Initial Reservoir Pressure (kPa)	Steam Chamber Pressure (kPa)	Social Supply Cost ($/bbl)	Recovery (%)	CDOR (m^3/d)	Cum. SOR (m^3/m^3)
0	600	~ 2800	9.27	81.7	99	3.47
0	3100	3100	8.54	75.1	74	2.88
5	600	~ 1000	11.19	78.4	88	4.20
5	3100	3100	8.36	72.7	54	2.74
10	600	1300	12.70	65.5	84	4.73
10	3100	3100	8.24	71.3	56	2.67

Note: The steam chamber pressure is an approximation based on the three well pairs over the operating life.

Bitumen recoveries decrease with increasing gas cap thickness for depleted and non-depleted cases. Recoveries are approximately 6% better for the depleted 0 m and 5 m gas cap cases than for the non-depleted cases. The depleted 10 m gas cap recovery, however, is poorer than for the non-depleted 10 m case. This performance trend is similar to that observed for Wolf Lake.

In summary, definitive conclusions about the effect of gas cap depletion on SAGD performance were not obtained for the Clearwater at Burnt Lake. Uncertainties about the accuracy of the model in representing Burnt Lake, particularly with respect to pressures and the influences of solution gas, limit the authors' confidence in the validity of the predictions.



Suncor Inc. Resources Group

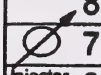
Burnt Lake Thermal Project
Type Log
7-23-67-3 W4M

Figure | November 1995

Figure 7.1 — Cold Lake Oil Sands — Burnt Lake Area Reference Well

BURNT LAKE CLEARWATER FORMATION
RESERVOIR PARAMETERS FOR 2D MODEL

GRID NO.	POROSITY (PHI)	WATER SATURATION (Sw)	Oil Saturation (So)	Ki=Kj	Kk
17	0.32	0.25	0.75	2500	1500
16	0.32	0.25	0.75	2500	1500
15	0.32	0.25	0.75	2500	1500
14	0.32	0.25	0.75	2500	1500
13	0.32	0.25	0.75	2500	1500
12	0.32	0.25	0.75	2500	1500
11	0.33	0.20	0.80	2500	1500
10	0.33	0.20	0.80	2500	1500
9	0.29	0.30	0.70	3000	1500
8	0.29	0.30	0.70	3000	1500
7	0.29	0.30	0.70	3000	1500
6	0.30	0.45	0.55	1700	500
5	0.30	0.45	0.55	1700	500
4	0.30	0.45	0.55	1700	500
3	0.22	0.60	0.40	1500	100
2	0.22	0.60	0.40	1500	100
1	0.22	0.60	0.40	1500	100



2m grid blocks in the k direction.

Table 7.1

Burnt Lake Clearwater Gas Effect Study
Supply Cost Summary
Discounted @10% to 1995 Dollars

Cost Centre	0m Gas Cap Depleted (Live Oil) Supply Cost	0m Gas Cap Depleted (Dead Oil) Supply Cost	0m Gas Cap Nondepleted Supply Cost	5m Gas Cap Depleted Supply Cost	5m Gas Cap Nondepleted Supply Cost	10m Gas Cap Depleted Supply Cost	10m Gas Cap Nondepleted Supply Cost
Capital Cost							
Drilling	$7.40	$7.42	$8.25	$8.93	$8.27	$11.27	$8.41
Seism/Delin/Eng	$0.32	$0.32	$0.31	$0.34	$0.32	$0.35	$0.32
Steam Facilities	$5.63	$5.57	$4.76	$7.72	$4.45	$8.82	$4.13
Other Facilities	$12.58	$12.62	$12.54	$13.38	$12.67	$13.90	$12.71
Total Capital	$25.92	$25.92	$25.86	$30.36	$25.71	$34.34	$25.56
Operating Cost							
Gas Cost	$18.01	$18.37	$15.02	$24.04	$14.24	$28.32	$13.77
Utilities	$4.83	$4.92	$4.03	$6.45	$3.82	$7.63	$3.69
Production Treating	$0.78	$0.78	$0.78	$0.79	$0.78	$0.79	$0.78
Water Treating	$1.45	$1.48	$1.24	$1.48	$1.18	$1.25	$1.14
Fixed and Other	$6.83	$6.85	$6.80	$7.26	$6.88	$7.55	$6.90
Total Operating Cost	$31.90	$32.39	$27.88	$40.02	$26.89	$45.54	$26.28
Total Cost/m3 BIT	$57.83	$58.32	$53.74	$70.38	$52.60	$79.88	$51.85
Total Cost/bbl BIT	$9.19	$9.27	$8.54	$11.19	$8.36	$12.70	$8.24
Plant Summary							
Number of wells	112	108	122	118	128	152	128
Cum Bitumen Produced (E3m3)	47,784	47,182	47,901	48,447	47,497	47,472	46,444
Cum Steam Injected (E3m3)	160,283	162,923	137,186	204,583	128,492	231,483	122,111
Cum Water Produced (E3m3)	155,251	157,527	135,439	158,705	127,363	122,916	121,683
Plant CDOR (m3/d)	4,364	4,309	4,375	4,424	4,338	4,335	4,241
Plant CSOR (m3/m3)	3.35	3.45	2.86	4.22	2.71	4.88	2.63
Bitumen Capacity Utilization	91.5%	90.4%	91.7%	92.8%	90.9%	90.8%	88.9%
Steam Capacity Utilization	76.4%	77.7%	65.4%	97.6%	58.3%	1.05%	58.2%
Avg. Well Summary							
Pattern Life (yrs)	12.25	12.75	15.50	13.75	17.50	12.00	19.50
Cum Bitumen Produced (E3m3)	447	458	421	440	408	367	399
Cum Steam Injected (E3m3)	1,493	1,592	1,215	1,847	1,119	1,736	1,067
Cum Water Produced (E3m3)	1,478	1,573	1,225	1,485	1,133	925	1,085
Well CDOR (m3/d)	100	99	74	88	64	84	56
Well CSOR (m3/m3)	3.34	3.47	2.88	4.20	2.74	4.73	2.67
Recovery (90m spacing)	79.7%	81.7%	75.1%	78.4%	72.7%	65.5%	71.3%

Table 7.2

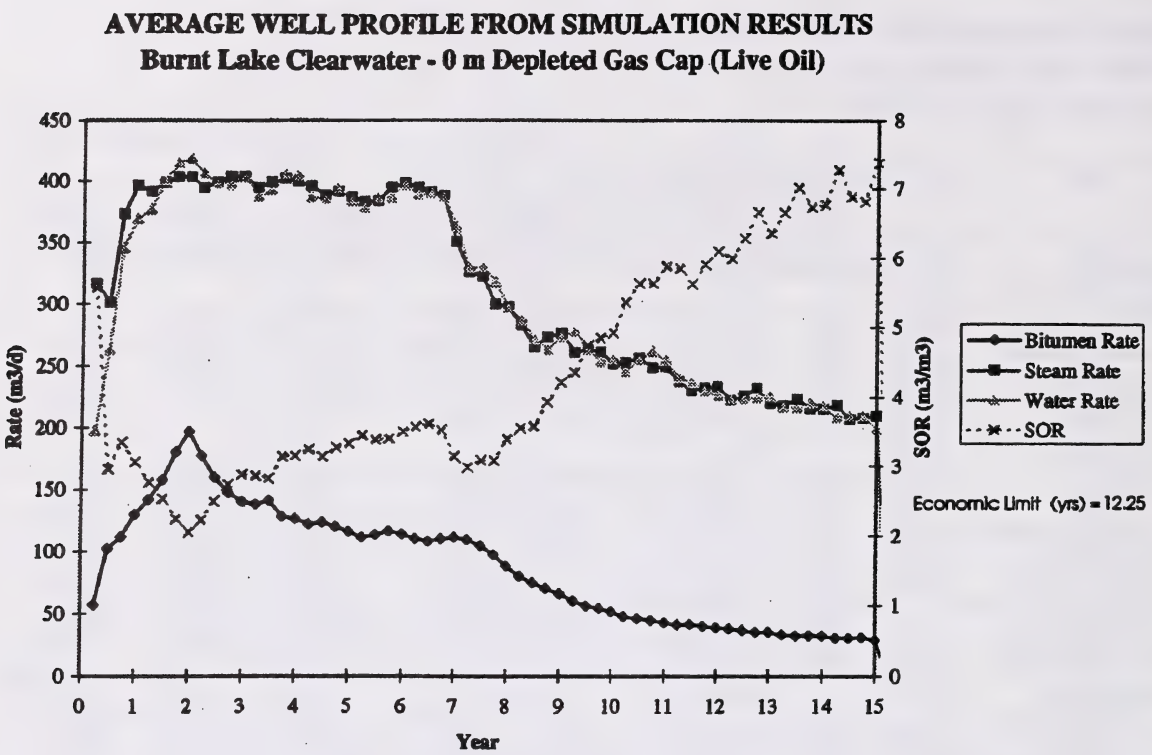

AVERAGE WELL PROFILE FROM SIMULATION RESULTS
Burnt Lake Clearwater - 0 m Depleted Gas Cap (Live Oil)
Rate (m3/d)
SOR (m3/m3)
Year
Bitumen Rate
Steam Rate
Water Rate
SOR
Economic Limit (yrs) = 12.25

Figure 7.2

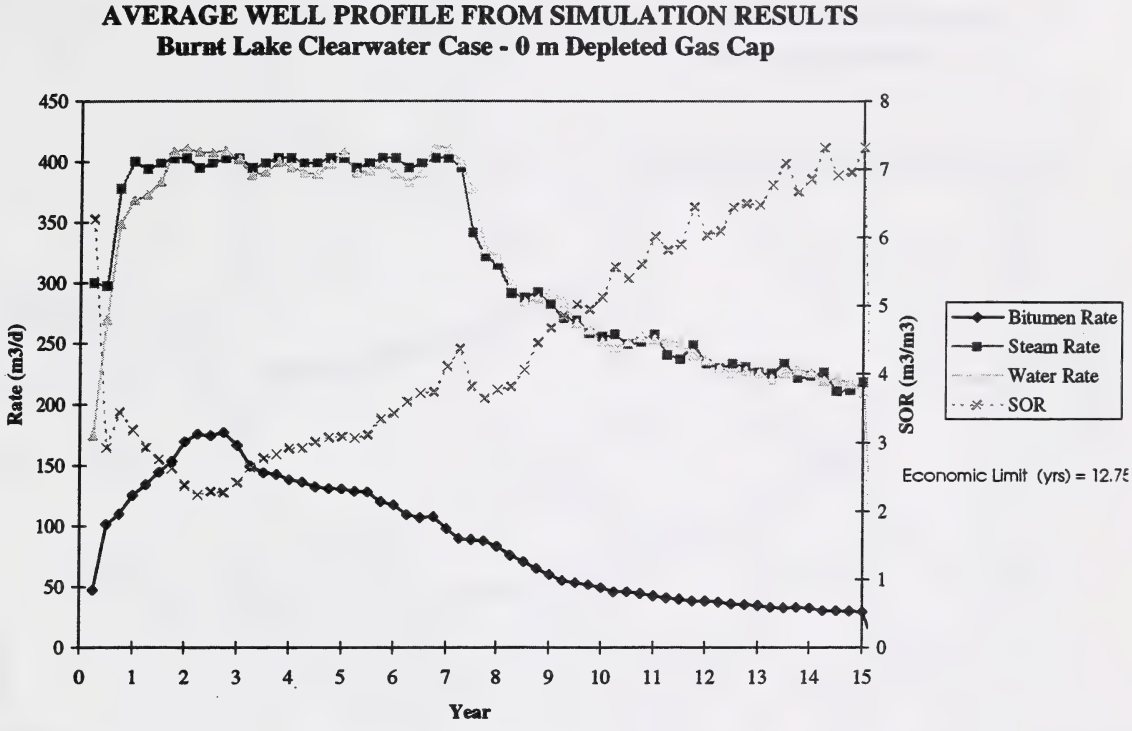


Figure 7.3

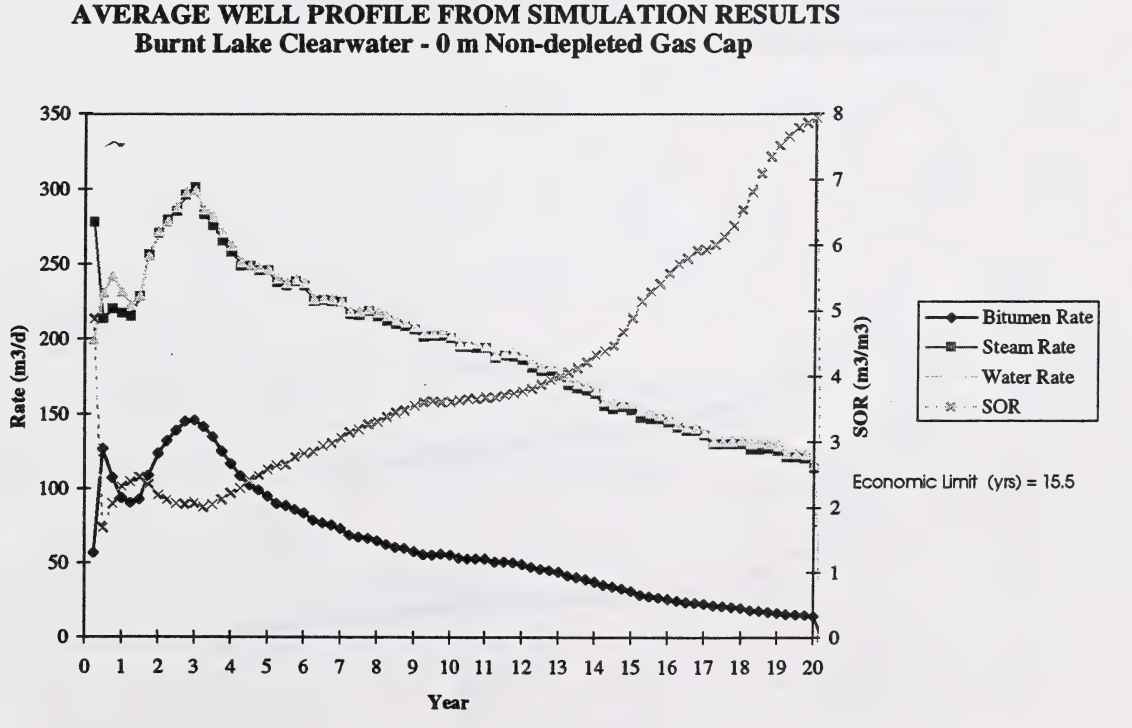


Figure 7.4

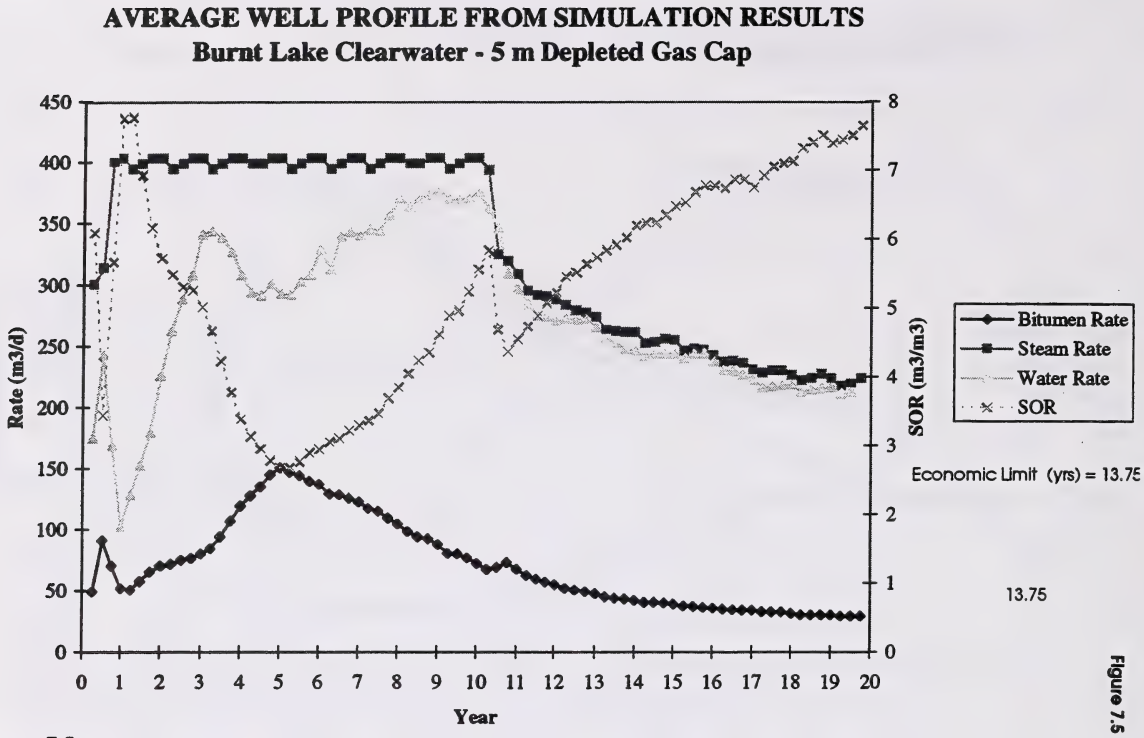


Figure 7.5

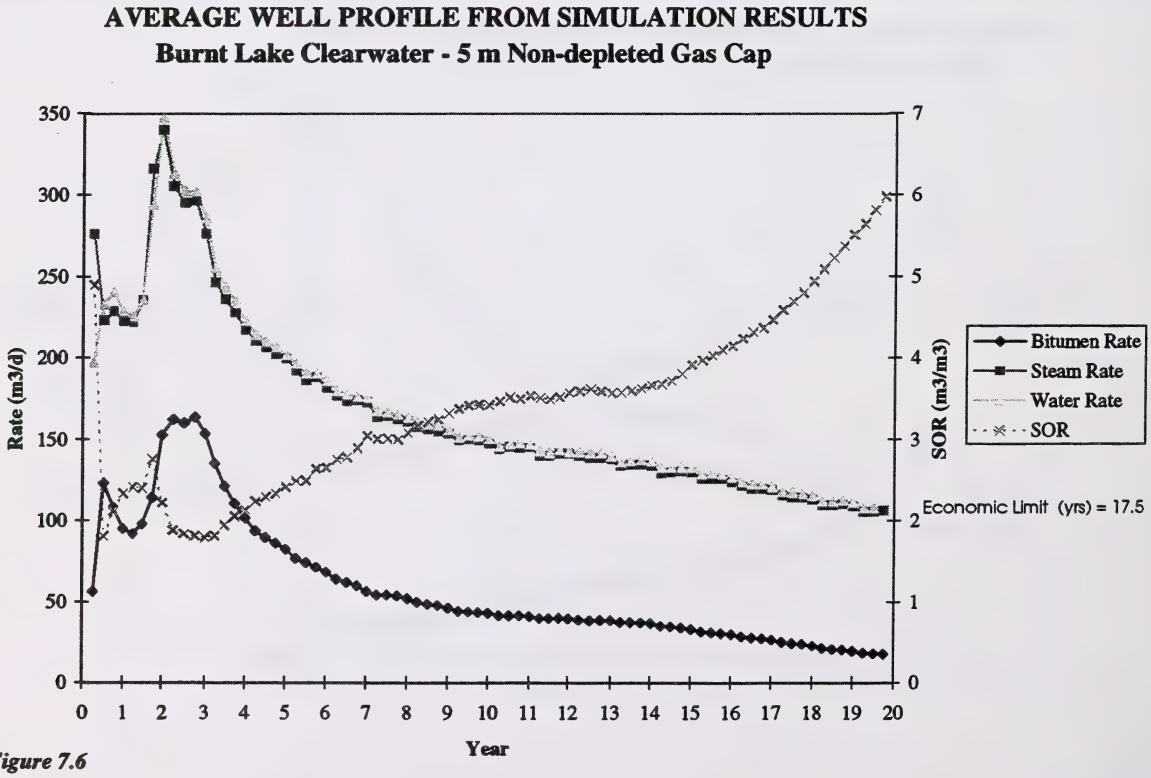


Figure 7.6

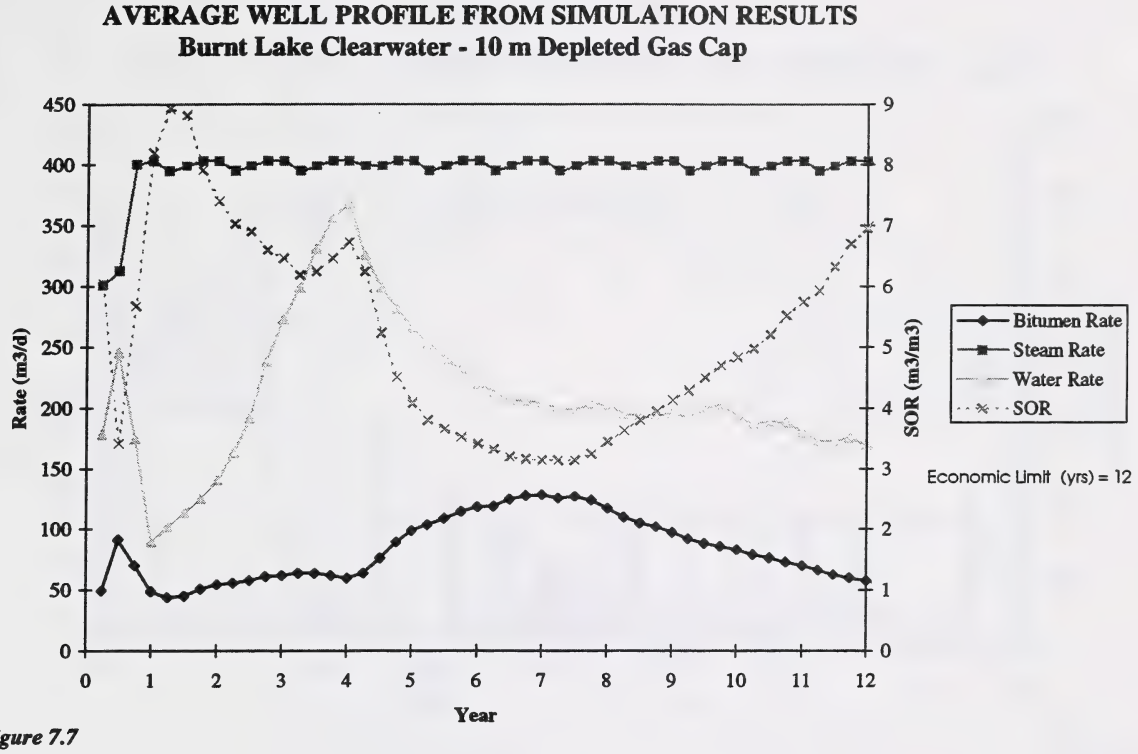


Figure 7.7

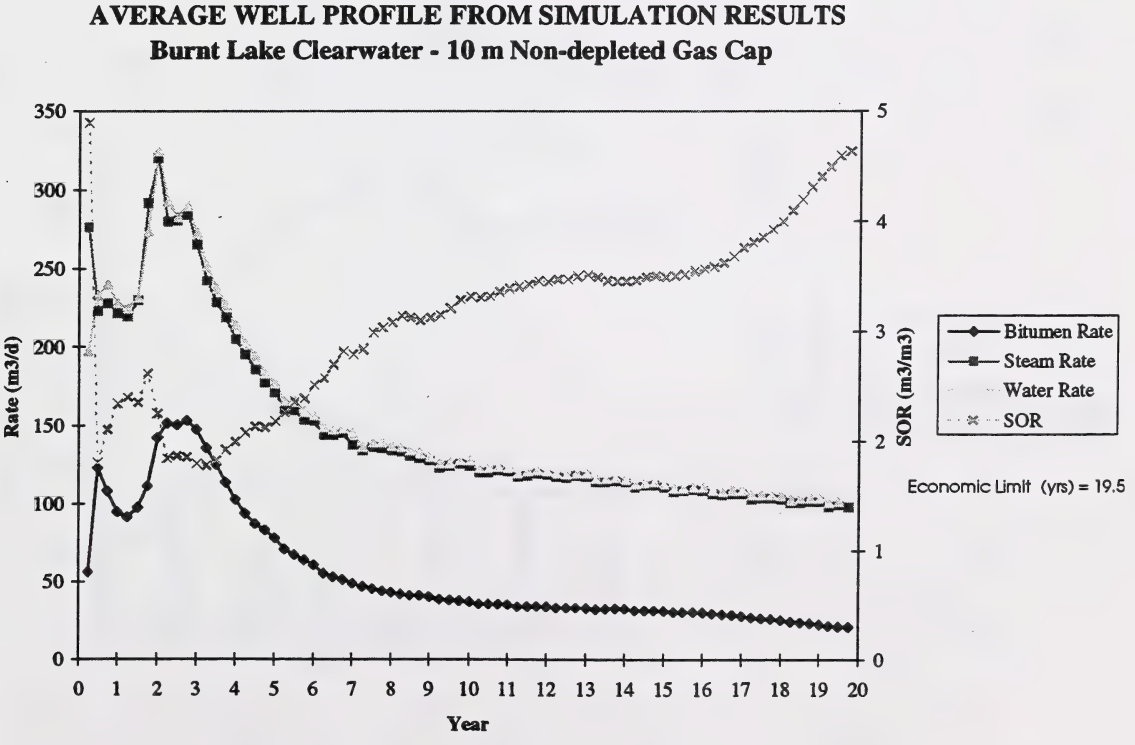


Figure 7.8

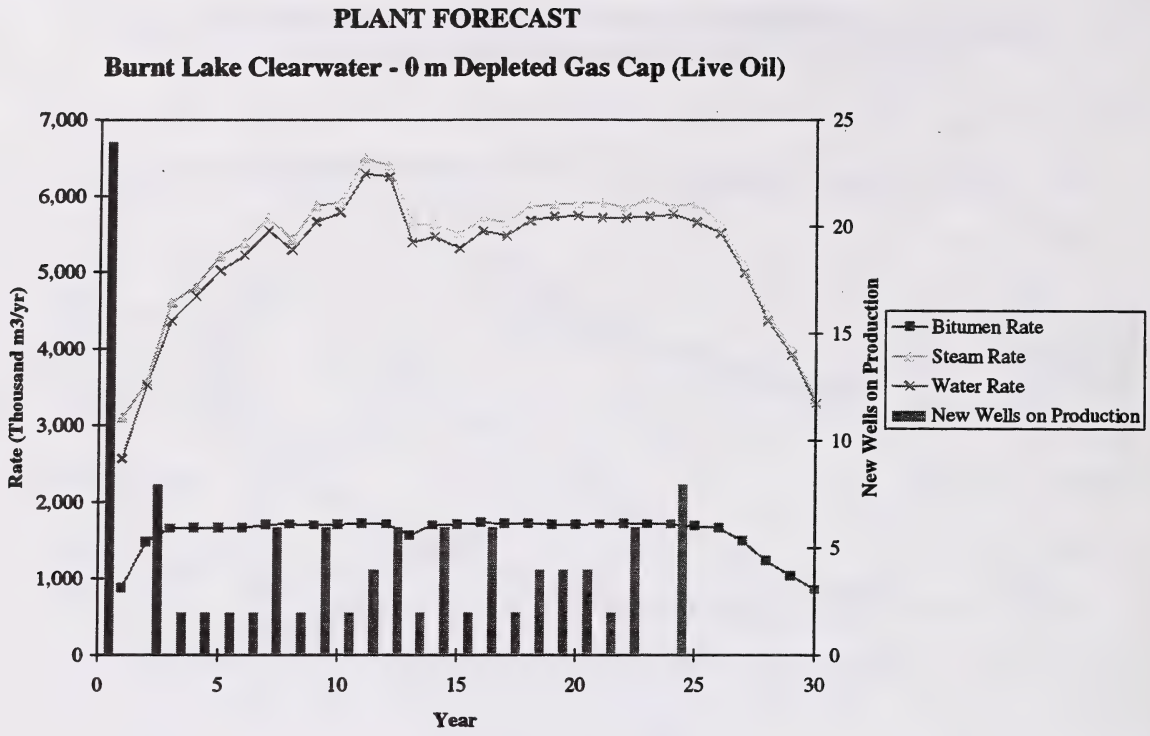

PLANT FORECAST
Burnt Lake Clearwater - 0 m Depleted Gas Cap (Live Oil)
Rate (Thousand m3/yr)
New Wells on Production
Year
Bitumen Rate
Steam Rate
Water Rate
New Wells on Production
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
25
20
15
10
5
0
0
5
10
15
20
25
30

Figure 7.9

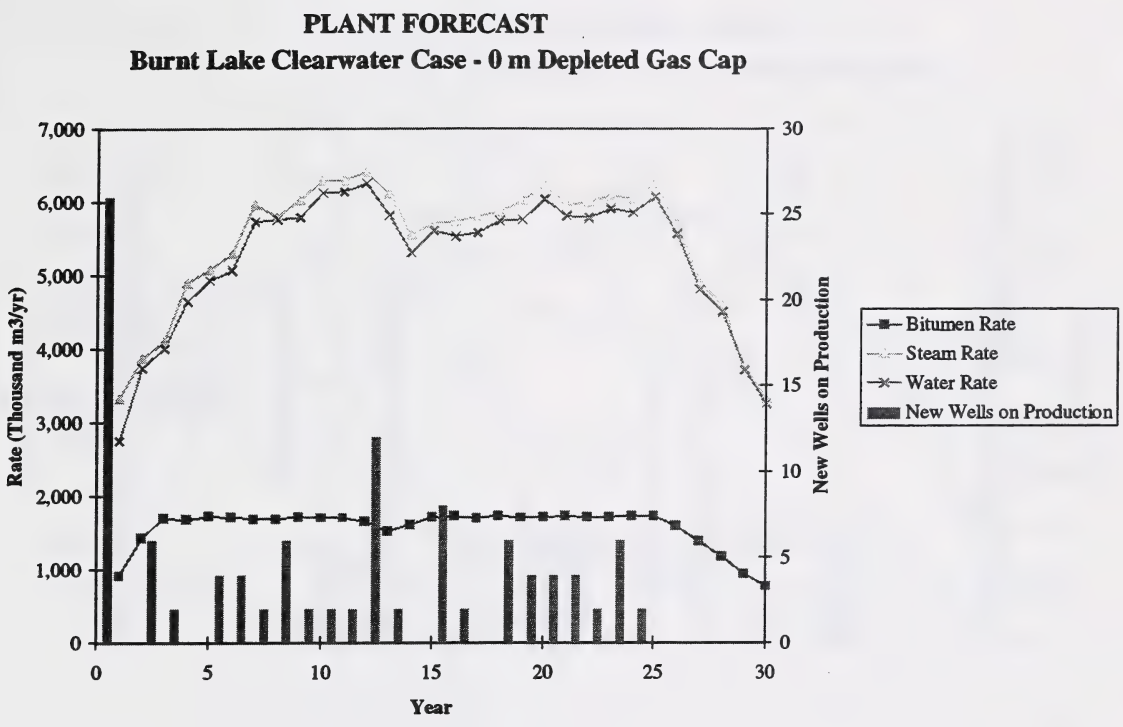


Figure 7.10

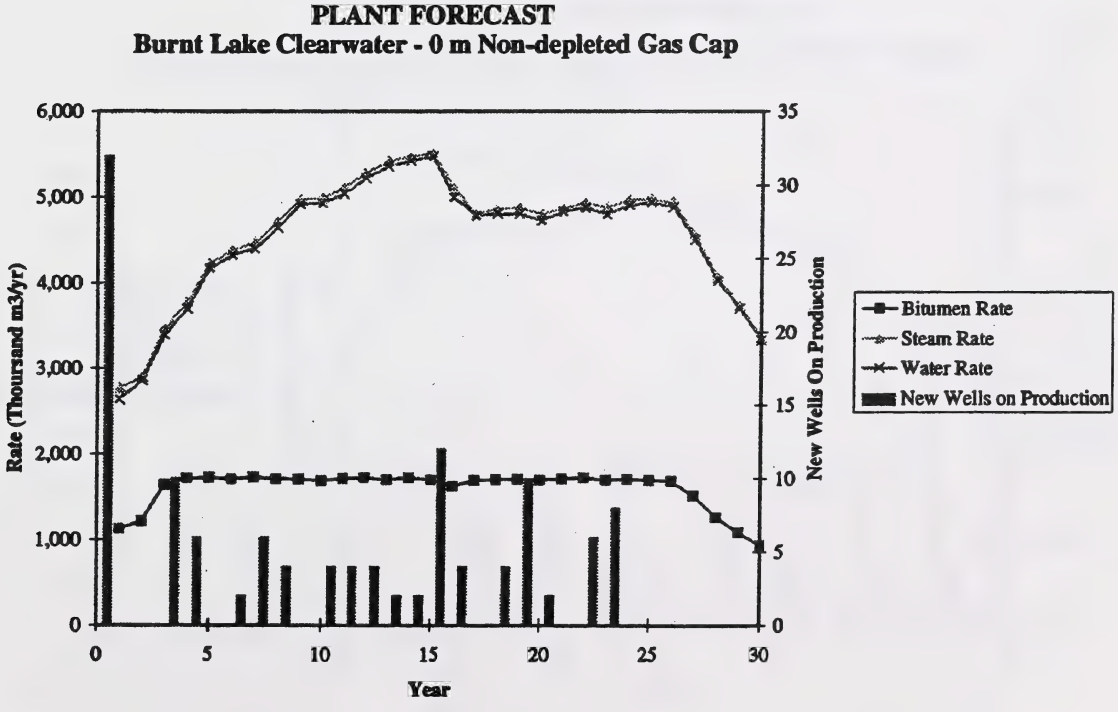


Figure 7.11

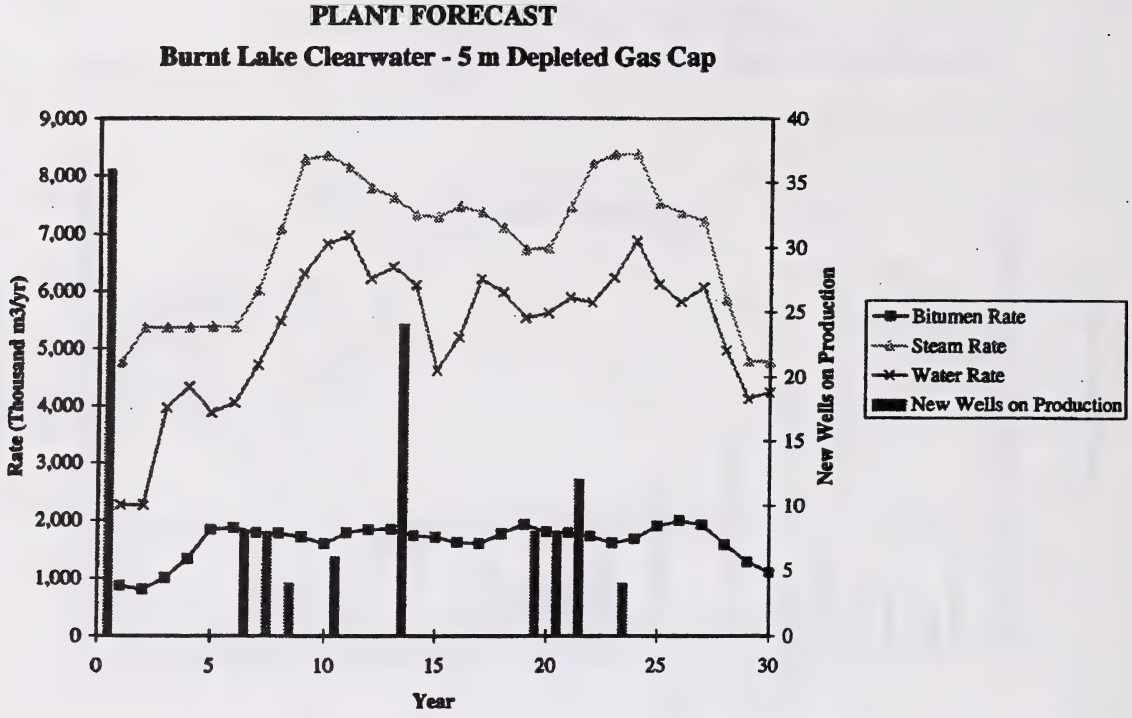


Figure 7.12

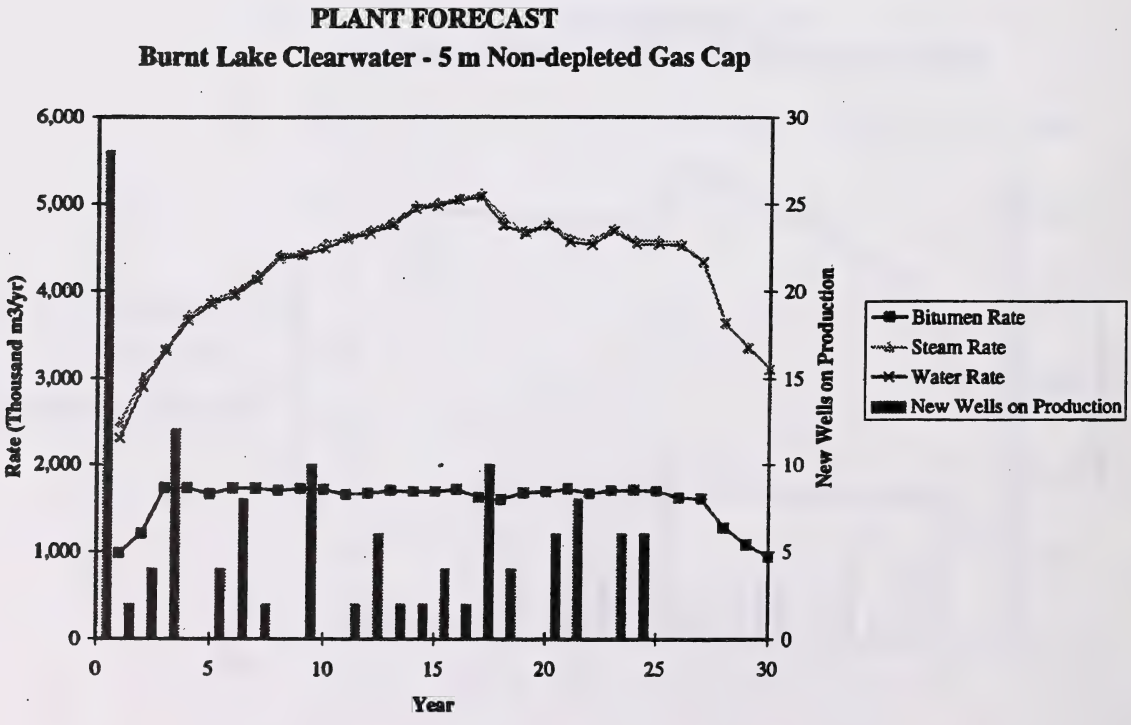


Figure 7.13

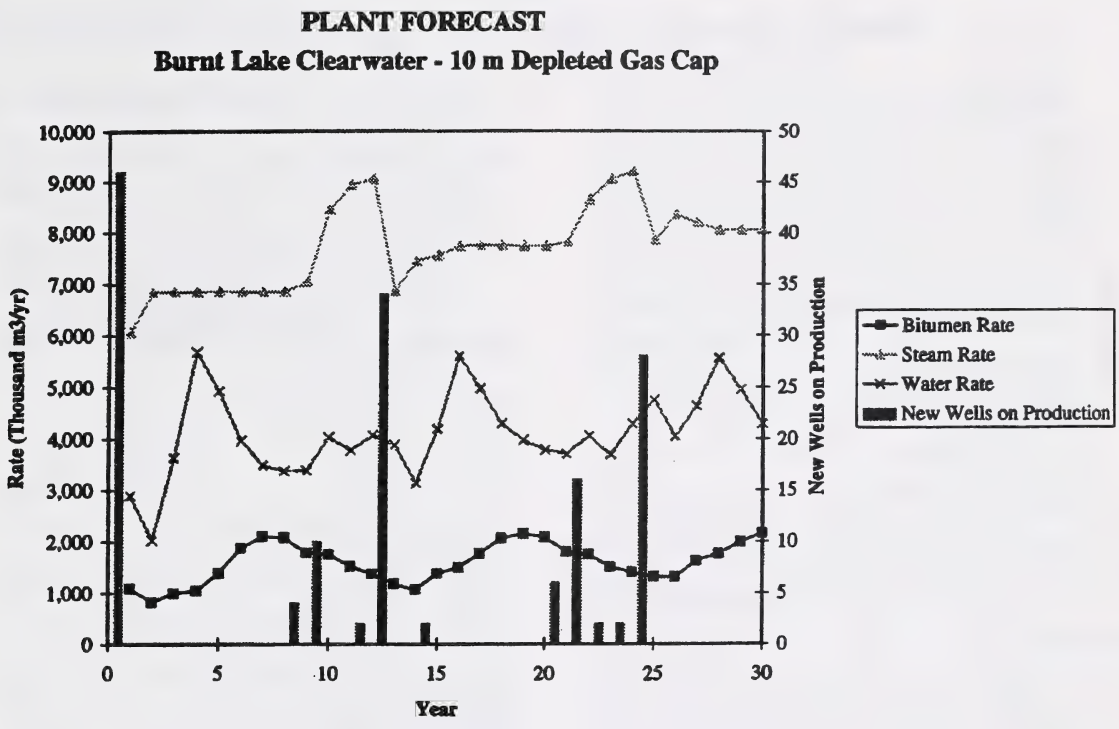


Figure 7.14

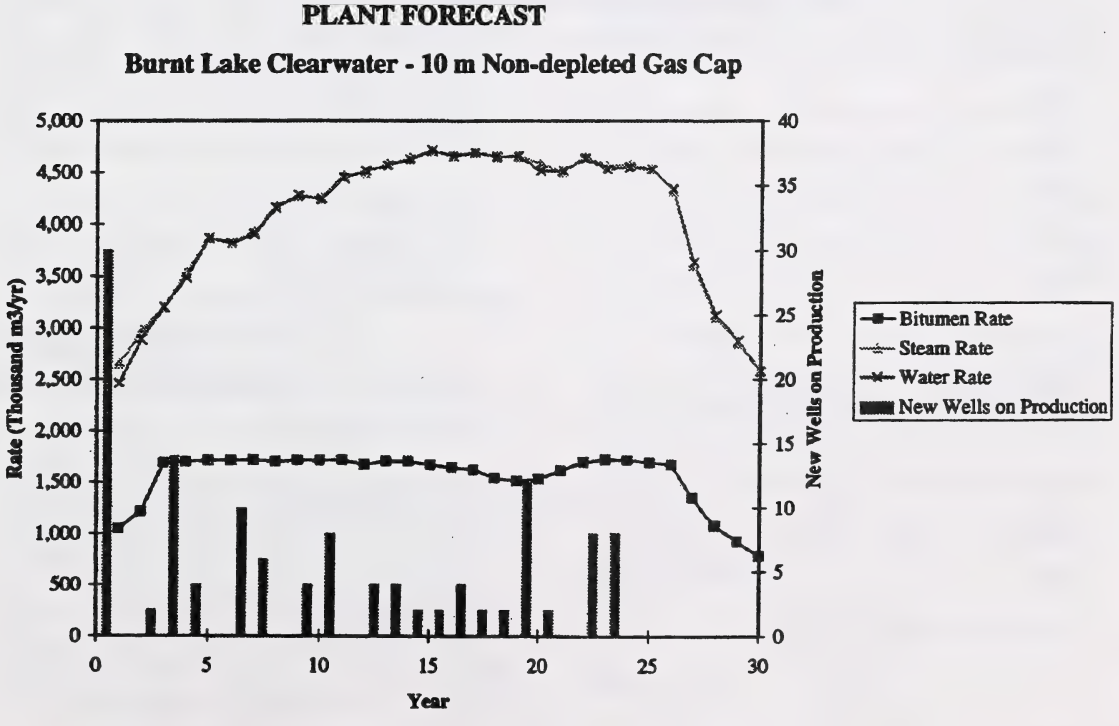


Figure 7.15

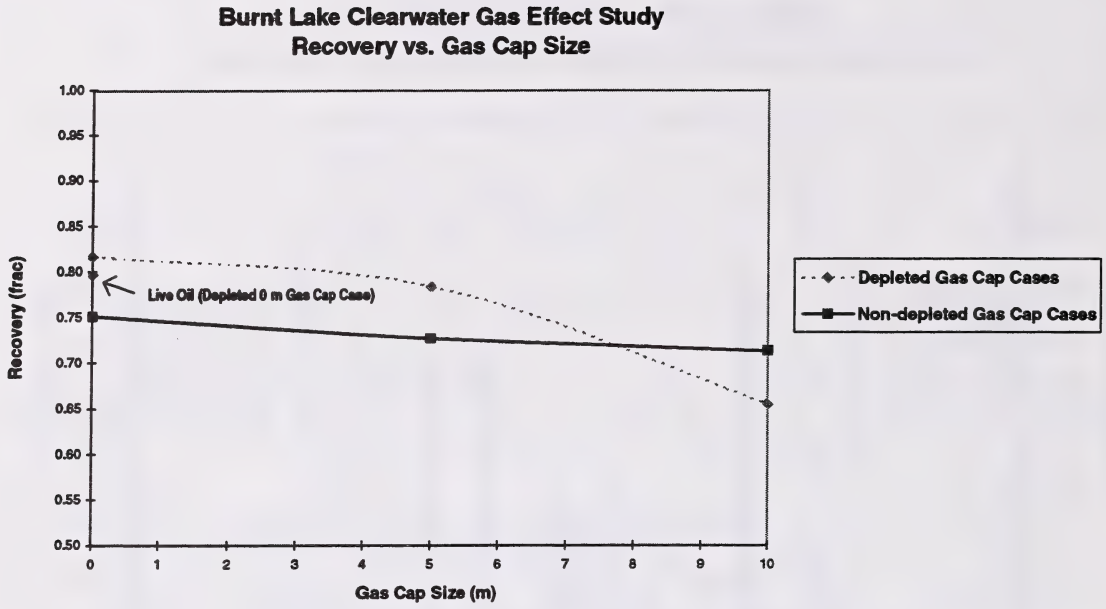

Burnt Lake Clearwater Gas Effect Study
Recovery vs. Gas Cap Size
Recovery (frac)
Gas Cap Size (m)
Live Oil (Depleted 0 m Gas Cap Case)
Depleted Gas Cap Cases
Non-depleted Gas Cap Cases

Figure 7.16

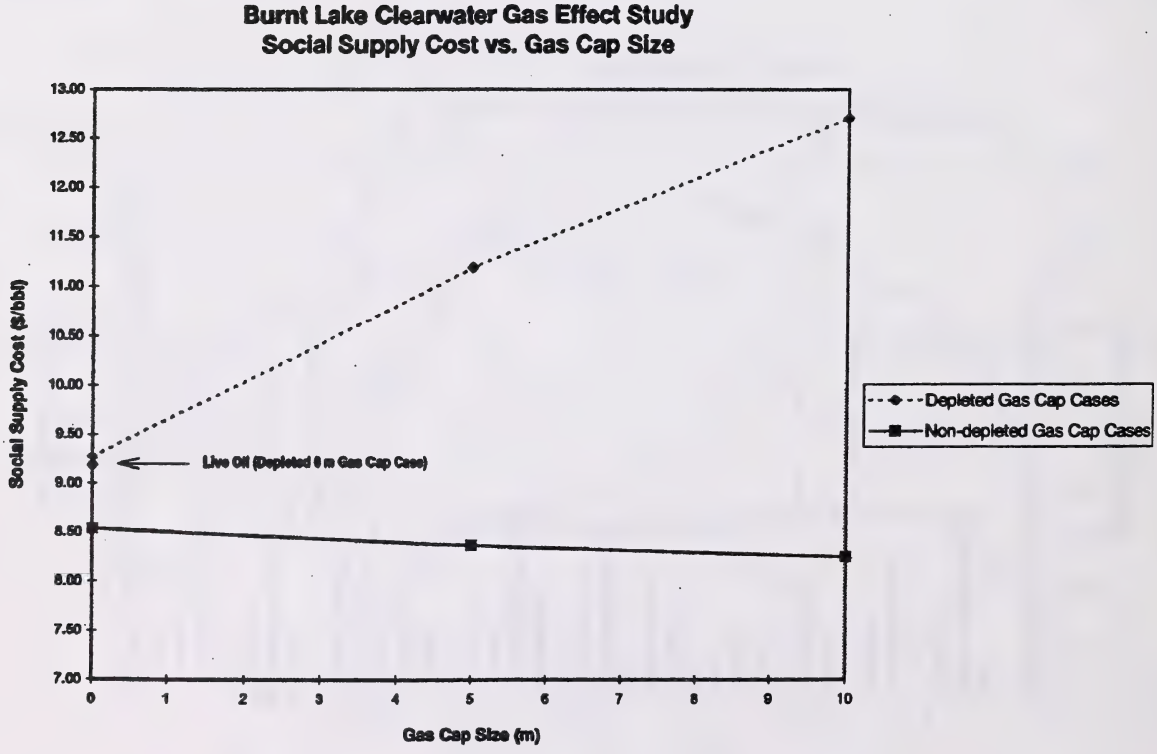

Burnt Lake Clearwater Gas Effect Study
Social Supply Cost vs. Gas Cap Size
Social Supply Cost ($/bbl)
Gas Cap Size (m)
Live Oil (Depleted 0 m Gas Cap Case)
Depleted Gas Cap Cases
Non-depleted Gas Cap Cases

Figure 7.17

8.0 Summary of Findings

8.1 Athabasca McMurray Formation

- In Athabasca, there are gas accumulations interpreted as being in contact with the Wabiskaw/McMurray oil sands.
- Depletion of gas cap pressure as a result of gas production means that the recovery process — SAGD in this study — must be operated at a lower pressure to minimize steam leak-off to the gas cap during the period when the steam chamber is in contact with the gas cap.
- Numerical simulations for a number of cases where gas caps are not being produced suggest that the social supply cost will not be significantly affected by operating at the original gas cap pressure. Recovery, however, may be reduced slightly (2 or 3 percentage points) as gas cap thickness increases.
- In cases where the gas cap has been depleted, numerical simulations suggest that, when the SAGD process is operated at pressures comparable to those cases without gas cap depletion (2600 kPa), significant steam is lost to the gas cap and recovery and economics are poorer. By restricting steam loss and operating at 1000 kPa (450 kPa above depleted gas cap pressure for the case involving a 10 m thick gas cap), the decrease in bitumen recovery is not as severe (69% as compared to 79%). The social supply cost increases by approximately $1.50 per barrel of bitumen from $9.04 to $10.53/bbl. It appears that the effect on the SAGD process of thinner gas caps is less severe due to partial plugging with displaced bitumen. One case operated at 550 kPa, the same as the gas cap pressure, resulted in a social supply cost of $9.32 per barrel of bitumen although recovery was very low at 41%.
- Although further optimization may be possible, it is concluded that bitumen recovery for thicker gas caps may be lowered by about 10% and discounted social supply cost may be increased by up to $1.50 per barrel of bitumen by depletion of associated gas.

8.2 Clearwater Formation, Wolf Lake

- At Wolf Lake, the Clearwater is overlain by associated gas in certain areas.
- Numerical simulations suggest that the social supply cost will be favoured by operating at or close to the original gas cap pressure to minimize steam losses to the gas cap.
- In the non-depleted reservoir cases, the social supply costs for the 0 m gas cap, the 4 m gas cap, and the 8 m gas cap are $11.63/bbl, $11.53/bbl, and $11.07/bbl, respectively. Bitumen recoveries are 57.7%, 59.2%, and 58.5%, respectively. In the depleted reservoir cases, the social supply cost for the above cases are $12.65/bbl, $11.56/bbl, and $11.25/bbl, respectively. Bitumen recoveries are 64.3%, 61.6%, and 58.4%, respectively.
- In all depleted and non-depleted cases, the presence of the gas cap increases production and reduces steam oil ratio compared to the cases with no gas cap or even thinner gas cap zones. These results, which appear to contradict those for the Athabasca, are attributed to a greater insulating effect.
- The depleted low-pressure cases have long pattern lives which could be shortened by operating strategy and by reducing interwell spacing. Similar optimizing techniques could be pursued for all the cases studied.
- In general, the interaction of a steam front with a gas cap and liberated solution gas is very complex. The behaviour has both advantageous and disadvantageous features. SAGD performance will depend on optimizing operation procedures, particularly with respect to pressure management.
- Based on relatively small incremental social supply costs offset by some improvement in bitumen recovery, depletion of gas caps may not be detrimental to SAGD performance at Wolf Lake. Any conclusion, however, must be qualified by uncertainty about the effect Wolf Lake bitumen solution gas has on the SAGD process and the ability of the model, which has not been verified by Wolf Lake field data, to accurately predict performance.

8.3 Clearwater Formation, Burnt Lake

- At Burnt Lake, six cases were numerically simulated: depleted and non-depleted cases for 0 m, 5 m, and 10 m gas caps. Unfortunately the programmed steam chamber pressures exceeded the gas cap pressures for the depleted gas cap cases and the effect of producing at the gas cap pressure was not simulated.
- In non-depleted reservoir cases, the social supply cost for 0 m, 5 m, and 10 m gas caps are $8.54, $8.36, and $8.24 per barrel of bitumen, respectively, showing the same trend as Wolf Lake, due possibly to the greater insulating effects of gas caps. Bitumen recoveries are 75.1%, 72.7%, and 71.3% respectively. As concluded for Wolf Lake, results must be qualified by uncertainty about solution gas effects and the validity of the model used to predict performance.

8.4 Other Considerations

Other considerations not specifically addressed elsewhere in this report but which may warrant additional studies are summarized as follows:

- The SAGD simulation results at the different sites studied are strongly dependent on the descriptions of reservoir geology. Gas cap thickness is only one of the geological parameters that affect performance.
- Numerical models currently available may not properly address the interaction between non-condensible gas and steam vapour, particularly diffusion effects. As a steam chamber contacts an overlying associated gas sand, densities of each at the operating pressure at the time may become important. There may be an optimum pressure from a density standpoint. Further investigation of this effect is warranted.
- The ideal steam chamber operating pressure in the case of gas caps from a steam loss perspective is the same as that of the gas cap at the time. At expected gas cap depletion pressures, 500 kPa or less, SAGD production wells may be unable to transport fluids to the surface even with gas lift. An efficient artificial lift method capable of high production rates of fluids at close to steam saturation conditions is required. Although an efficient method does not exist at this time, development is expected to occur to satisfy this need.
- The effect of producing gas caps on the Athabasca McMurray Formation is not well understood. One prominent theory suggests that solution gas in bitumen in the Athabasca oil sand has been released over time, flowing to the surface and being replaced by fresh surface water. Associated gas caps in question are small accumulations in highs on the Wabiskaw/McMurray oil sand. If this is so, one would expect fresh water to invade these accumulations as the gas is produced. Pressure performance during gas production suggests, however, that this is not occurring, in the short term at least.
- The geology, particularly the permeability and interbedded shaly nature of the Upper McMurray Formation, is complex. Lateral pressure and fluid communication in the Upper McMurray, as suggested above, is probably poor. Although gas depletion may influence pressure in the oil sand immediately beneath the gas pool, its effect on oil sands laterally distant from the gas pool may not be significant. Monitoring of pressure in the upper water/gas sands, particularly at various lateral distances from gas production, is warranted.
- Numerical simulations and predictions in this study did not address how new SAGD patterns would be started adjacent to depleted patterns. Two methods are being considered. One is to maintain pressure by injecting gas into depleted patterns as steam vapour condenses, some of this gas being produced later. The other is to leave a buffer region between development stages and allow pressure in depleted stages to decline as the steam vapour condenses.

9.0 Further Work

Much remains to be done to improve our understanding of the phenomena studied and to quantify the effects discussed in this report. Additional factors that may influence SAGD performance should also be addressed:

- Additional study and field testing are required to define the possible effects on SAGD performance of water sands overlying the bitumen, as well as the combined effects of overlying water and gas.
- The mechanism of bitumen movement into the gas zone and/or water sand and the degree of plugging need to be demonstrated. Physical modelling studies would be useful in validating the interpretation of numerical simulations of this phenomenon.
- Mixing of associated gas and process steam may occur, with potential implications for both gas and bitumen recovery processes. Further investigation is needed to evaluate these effects.
- Communication behaviour in water sands overlying bitumen deposits and underlying gas accumulations should be addressed from the standpoints of lateral pressure communication and the provision of pressure support to gas caps from either expansion of the aquifer or surface water influx (charge to the aquifer).
- The effect of bitumen saturation and the lithology of the reservoirs, including grain size, permeability, and the presence of clay stringers on the role of associated gas caps, warrants further study.
- The method used in abandoning bitumen-depleted oil sands may well affect the recovery of associated gas. This issue should be addressed.
- Development of an efficient artificial lift method is required for low-pressure SAGD operations where thermal lift supplemented by gas is no longer effective.
- Modified or alternative bitumen recovery processes are being explored and developed. Two processes with potential, Vapex and COSH, are undergoing laboratory testing. Subject to successful laboratory and field testing, these processes may be employed to improve SAGD performance in low-pressure applications.

10.0 Glossary

Social Supply Cost

Cost per unit of production over the project life that will provide the rate of return implied by the discount rate, before taxes and royalties. In this study, capital and operating costs and oil or bitumen produced have been discounted at 10%.

Pattern Life

The length of time over which a well pair is economically operated.

Calendar-Day Oil Rate (CDOR)

The volume of oil or bitumen produced during a given period of time, pattern life, for example, divided by the number of days in that period of time.

Cumulative Steam/Oil Ratio (CSOR)

The cumulative volume of water required to make the steam injected, divided by the volume of oil or bitumen produced during the same period of time.

Live Oil

Oil or bitumen that contains dissolved gas. Generally speaking, the volume of dissolved gas in oil or bitumen is a function of temperature and pressure—the lower the temperature and pressure, the less dissolved gas. In the Cold Lake deposit, bitumen occurs at relatively high temperatures and pressures and is considered live. The presence of dissolved gas tends to reduce the density and viscosity of the oil or bitumen.

Dead Oil

Oil or bitumen that contains no dissolved gas. In the Athabasca deposit, bitumen contains relatively small volumes of dissolved gas because of low temperature and pressure and is often considered dead oil for simulation purposes.

Viscosity

A measure of a material's ability to flow. Low-viscosity material flows more readily than high-viscosity material. The viscosity of oil or bitumen is a function of a number of factors including temperature, chemical make-up, and dissolved gas content.

Heating Values of Natural Gas and Bitumen

Natural gas at standard temperature and pressure of 15°C and 1 atmosphere comprises mainly methane and has a net heating value in the order of 1000 Btu/ft^3 or 0.0373 GJ/m^3. Bitumen at the same standard conditions has a heating value in the order of 42,000 kJ/kg or 42 GJ/m^3. Accordingly, for equivalent standard volumes, the ratio of the heating value of bitumen to that of natural gas is in the order of 1126 to 1.

Volume Equivalency

1 cubic metre (m^3) = 6.293 barrels (bbl)

Appendix A

Well-Pair Economic Limit Assumptions and Artificial Lift Considerations

Well Pair Economic Limit

The well pair economic limit applied in this study is described below. Assumptions used in the study are based to a large extent on experience with the Underground Test Facility project and commercial plant studies of the Steam Assisted Gravity Drainage (SAGD) process conducted by the Alberta Department of Energy.

Bitumen Production Rate Limit (No Steam Cost)

Production Well Incremental Operating Costs:

Well operating cost:	Assume $200,000/year
Oil treating:	Chemical Costs $0.59/m^3 oil
Water treating & handling:	(included in Steam Cost)
Average bitumen price:	$9.41/bbl or $59.19/m^3
Economic limit	= 200,000/(59.19 – 0.59) 365 = 9.35 m^3/d

Bitumen Production Rate Limit (with Steam Cost)

Steam generation costs:

Boiler feed water treatment:	$0.69/m^3 water (industry average)
Produced Water Treatment:	$0.18/m^3 water
Gas Cost:	Energy required 2.7GJ/m^3 (80% quality) Gas cost $2.00/GJ Gas cost for Steam 2.00 x 2.7 = $5.40/m^3 steam
Water source and disposal operating cost:	(700 m^3/d) $200,000/year or $0.78/m^3 water

The relationship between the bitumen production rate and the steam/oil ratio limit is summarized in Figure A1 for gas costs of $1.65, $2.00, $2.20 and $2.75 per GJ.

The figures show that annual well pair operating costs have a major impact on the economic limit. These costs, however, are not available for horizontal SAGD wells operated from the surface due to limited experience with this process and no experience with the later well life. Critical costs, in addition to normal operating manpower and maintenance costs, will be associated with artificial lift (gas lift or rod pumps), corrosion and sand control/handling. Action which incurs significant costs may not be economically justified and could result in the well pair being shut in.

The assumed well pair operating cost of $200,000 per year is about 15% of the initial well capital cost. This approach has been adopted for the time being, subject to later modification when more data are available on well life performance and operating costs. In the foregoing, no value was assigned to the capital required for steam generation.

In practice, the economic return from a project may be optimized by discontinuing steam injection before the economic limit is reached and then directing the steam to newer wells. The later stage of a SAGD project would also involve wind-down, possibly with gas injection. This study has not considered optimization of the process, particularly the later stages.

Artificial Lift Considerations

The ability to lift produced fluid to the surface is a factor that will come into play as the operating pressure or steam chamber pressure is lowered to offset steam loss to overlying gas zone. The general practice to date and the expectation in normal operating conditions is that hot fluids will flash as production rises to the surface. The resulting reduced densities will enable desired flow rates to be achieved. The addition of gas to the heel of the production tubing provides additional lift at lower temperatures and production rates and stabilizes the well performance in certain situations.

Pressure drops in wellbores with multi-phase flow are difficult to calculate, particularly when influenced by heat transfer and phase changes. The Department of Energy contracted M.E. McCormack (Fractical Solutions Inc.) to study gas lift design for SAGD wells using his two-phase flow model based on the Beggs and Brill correlations. He developed a series of graphs showing wellhead producing pressure versus flow rates for various quantities of added lifting gas and assumed conditions of true vertical depths, tubing sizes, bottomhole pressures and steam quality at the heel of the production tubing.

Mr. McCormack says his results should be used with caution because of the uncertainties involved. However, some general observations are warranted:

1. Gas lift was found to be beneficial as an enhancement to the inherent natural steam lift present in SAGD production wells.
2. As expected increases in production rates raise velocities, the friction component of the pressure drop increases as a result. Larger tubing is needed for higher flow rates.
3. The principal benefit of gas lift is to improve the stability of the system by lowering the hydrostatic head of the produced fluid column at low flow rates. This results in

higher surface pressures at lower flow rates. The effect at higher flow rates is to slightly reduce the maximum flow rate possible due to increased frictional pressure drops.

4. The use of insulated tubing in the slant/vertical section of the well should normally act to improve the stability of the system.
5. Inlet fluid qualities of 5-10% at the bottom of the riser should generally give better performance than lower or higher fluid inlet qualities.

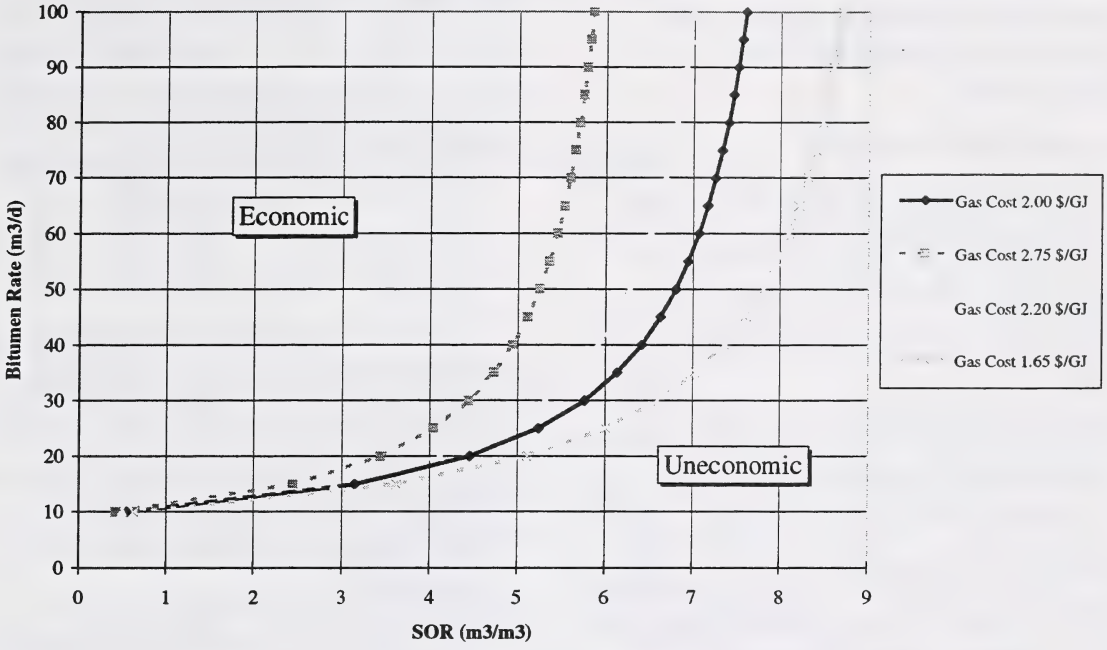
The following table shows bottomhole and wellhead pressures for typical production rates and overburden depths for Athabasca and Cold Lake as interpolated from the subject study.

In general, the table shows that lifting fluid in the situations addressed in this study may not be a problem except in the low-pressure cases. Fluid lifting can be accomplished with natural fluid energy (density reduction due to flashing as pressure is reduced) and gas lift as necessary at initial low rates and for stability at high rates. The additional cost of this lift gas will be minimal because it will be separated from the produced fluid and used as fuel gas in the steam generators.

Other artificial lift methods may be necessary in two cases (Athabasca Case 3 and Cold Lake Case 2) in the table which show low-flowing wellhead pressures with the suggested tubing sizes. As shown for Case 3, larger tubing does not seem to increase flowing wellhead pressure. In these cases, some additional expenditure for artificial lift and/or inlet booster pumps for the plant may be necessary, although this has not been included in this study. Development of pumping technology for high-volume horizontal well fluids at or close to steam saturations conditions is warranted. It is expected that this development will occur as the need is identified.

Case	Overburden (m)	Bottom Hole Pressure (kPa)	Production Rate			Suggested Tubing Size (inches)	Flowing Wellhead Pressure (kPa)
			Bitumen (m^3/d)	Water (m^3/d)	Total (m^3/d)		
Athabasca							
1	140	1400	90	190	280	3.5	1000
2	100	1000	70	150	220	3.5	650
3	50	500	50	90	140	3.5	325
						4.5	300
Cold Lake							
1	420	2500	180	500	680	4.5	1140
2	420	1000	100	350	450	4.5	225

Economic Bitumen and SOR Cutoffs for Different Gas Costs



Appendix B

Economic Model Description and Capital and Operating Cost Assumptions

Economic Model Description

The economic model used in this study was developed internally by Department of Energy staff for use in the commercial plant study for the Underground Test Facility. The commercial plant study selected 30,000 barrels of bitumen per day as the best size for the study given:

1) the probable reserves of 453 million barrels in that portion of the UTF lease being considered for commercialization, and
2) the need to capture significant economies of scale.

This study used the same commercial scale plant design of 30,000 barrels of bitumen per day.

Commercial plant forecasts are based on the typical well pair steam injection and bitumen and water production predictions obtained from numerical simulation of the SAGD process with specified reservoir conditions. Well pairs were brought on stream as necessary to maintain the plant at its bitumen production capacity. Wells were added to the system throughout the first 25 years of the 30-year plant life. It was reasoned that wells added after 25 years would not influence the social supply price. Although the capital cost to drill and tie-in the well would be paid out in most cases, the present value of the costs and production would not be significant. Bitumen plant capacity utilization, which had been found to have a significant effect on social supply price, was kept relatively high by providing adequate steam generation capacity.

Two models were used in generating commercial plant economics. The first was a well pair scheduling model, which resulted in a commercial plant yearly forecast of well pairs brought on stream, steam injection, and bitumen and water production. The second was the economic model, which took the yearly data from the scheduling model and calculated annual capital and operating costs based on cost input criteria. These costs as well as bitumen production were discounted back to current time to calculate a discounted social supply price, i.e., the sum of all discounted capital and operating costs divided by the discounted bitumen.

Capital and Operating Cost Assumptions

Capital and operating costs used in economics for SAGD scenarios considered in this study have been based on recent studies similar to these cases. Costs in these prior studies for commercial projects were obtained from a number of sources including operators and outside consultants.

The capital cost estimates for the facilities in prior studies were developed using a combination of equipment-factored estimating, capacity-factored estimating, and semi-detailed estimate techniques. The following is a summary of assumptions used in these preliminary designs and cost estimates.

1. Sufficient source water is available from nearby lakes and the cost estimate is based on this source.
2. The properties of the bitumen under consideration are similar to the bitumen properties at the UTF.
3. Diluent was added to facilitate bitumen water separation only. No additional diluent was added to meet pipeline specifications.
4. The properties of produced water under consideration are similar to the properties of produced water from the UTF.
5. A suitable horizon for the disposal of a portion of the produced water exists within a radius of 10 km of the plant site. Six wells will be sufficient for water disposal.
6. Waste products from the water-treating process (e.g., lime sludge) can be stored in surface pits on the lease.
7. Only minor upgrading of existing roads and minimal site work will be required.
8. Specific assumptions are itemized in Figure B1.

The central processing facility for the cases considered in this study was sized for oil production of 4770 m^3/d (30,000 bbl/d). This production rate is maintained by developing the reservoir in stages as discussed for each case. The steam facilities are sized according to the peak steam requirements of each case.

Specific Economic and Cost Assumptions

The following is a list of specific economic and cost assumptions and calculation factors used in the Alberta Department of Energy-EUB SAGD evaluation study.

General Assumptions:

- Well pairs are scheduled to fill 30,000 bpd.
- A minimum of two well pairs are added at one time.
- Wells are added to fill plant capacity for 25 years with a plant life 30 years.
- Plant startup is in year 2000.
- Costs are in 1995 dollars.
- Discount factor is 10%.
- No pipeline tariff costs are included.

Capital Cost Assumptions:

- Steam facility capital cost: yearly maximum steam rate (bspd) x $720 per bspd
- Other facility capital costs are assumed to be constant at $6,000 per nominal bopd plant capacity or $180 million.
- The steam facility capital cost was assumed to be a direct function of capacities required and does not reflect reduced costs per unit possible with larger capacities. This over-estimation of the costs for larger capacity steam facilities may be offset by additional costs for water sources, and treating and disposal facilities. These costs were not included.
- Well drilling costs on a per well pair basis are shown below:

	Athabasca	Wolf Lake
Surface Development (Roads, Pads, etc.)	$34,247	$34,247
Surface Facilities (includes gathering)	$559,589	$559,589
Well Costs	$756,164	$1,306,164
Total:	**$1,350,000**	**$1,900,000**

Operating Cost Assumptions:

- Gas cost: $2.20/GJ
- Steam cost $2.20/GJ x 2.548 GJ/$m^3$ steam x steam volume
- Diluent cost: 0.5% x 0.1162 bbls diluent/Bbl bitumen x Bitumen volume x $25/Bbl diluent
- Surface operating cost: $195,000/year
- Well abandonment (in Year 30): $50,000 per well pair
- Steam utilities cost: $1.51/$m^3$ steam x steam volume
- Fixed costs: $10,850,000 per year (staff, plant maintenance, materials)
- Production treating: $0.56/$m^3$ bitumen x bitumen production
- Water treatment: $0.47/$m^3$ water x water production
- Diluent cost: $25/Bbl
- Electrical power costs: $40/MWH
- Large blocks of wells are drilled over several years prior to the time needed to reduce short rig supply impact on costs.

Appendix C

Multi-Well-Pair Numerical Model Development for Analyzing Gas Cap Effects

Devopment of the Multi-Well-Pair Model

Numerous simulations were completed using 2D and 3D single-well-pair models, containing a horizontal well away from the well pairs in the gas cap. The horizontal well in the gas cap was used as an infinite sink with a constant back pressure equal to the initial reservoir pressure. The purpose of this well was to simulate a large gas zone which could not be pressured by the SAGD injection well. The gas cap size was varied from 1.5 to 10 m using the 24 m (bitumen reservoir) base case UTF model. In addition, several other cases were investigated using 8m of rich oil sands and 40 m of oil sands with varying gas cap sizes. The results of those cases demonstrated that:

- The 180 m lateral distance from the SAGD well pair to the low pressure gas cap allowed steam to move into the gas cap faster than was thought reasonable.
- One well pair would only model the outside well pair of any pattern. Inner pattern well pairs may be pressure-supported by inner steam chambers.

Early work on project centred on a phenomena referred to as "banking." The 2D model with a 3 m gas cap indicated a high-pressure gradient in the gas cap with a low-pressure gradient in the bitumen portion of the reservoir. This bank provided a "plug" which would not allow steam to break through to the low-pressure area. The plug would effectively seal or provide a barrier to contain the steam chamber. Once the plug reached the pressure sink, steam would quickly be removed from the model.

The model was changed from 2D to 3D by including a slice with higher-quality reservoir parameters. The 3D model was adjusted by removing the lower quality shale streaks in the lower portion of the model and consisted of one 100 m slice and another 400 m slice, referred to as layers j=1 and j=2, respectively. Subsequent simulation runs using the 3D model showed that plugging was still occurring in both the j=1 and j=2 layers.

Experience at the Kearl Lake Pilot Project located northeast of the UTF (described in the technical paper, "Steam Flooding For In Situ Bitumen Recovery at Kearl Lake Pilot in the Athabasca Oil Sands"), suggested that plugging did not occur in this water transition. At the Kearl Lake project, the bitumen is overlain by a water transition zone in the McMurray. Results of the project showed that steam was being lost from the pilot through the non-oil-bearing zone. In this study, a plug forms which prevents the breakthrough of steam to the pressure sink. Significant differences between the Kearl Lake Pilot Project and the current model are:

- Horizontal injector/producer well pairs at the UTF versus vertical wells at Kearl Lake.
- Top water zone thickness is not known at Kearl Lake. The thickness could be as much as 10 m and the model only had 5 m of attic water.
- Kearl Lake vertical wells were hydraulically fracture stimulated. These fractures could provide additional communication to the attic water zone.

Further work showed that when the gas cap (or attic water) thickness was 10 m or greater, no banking or plugging occurs. It was concluded that the banking was caused by bitumen that is heated and moved into a cold zone. Once heated, the bitumen is able to move into the gas or water zone since the mobility ratio of either gas or water is more favourable than cold bitumen (immobile). It should be noted that no sensitivity runs were completed using a smaller grid block in the gas cap. The effect of plugging could be sensitive to the size and number of grid blocks used. In this study, the gas cap grid blocks were each 2.5 m. The plugging could be a function of the area of breakthrough, the amount of bitumen moved to the gas cap and the gas cap thickness.

An earlier sensitivity case using a 10 m gas cap varied the short circuit layer thickness from 100 m to 2 m in a 90 m model. This case showed that the short circuit layer did somewhat alter the oil rate profiles. The oil rate was slightly higher in the 100 m short circuit case compared to the 2 m case by 125 m^3/d and 110 m^3/d, respectively. One interesting point is that the steam did not break through as quickly in the 2m case compared as in the 10 m case. This might be because of the small grid block surface area, which resulted in higher heat losses as the steam chamber advanced towards the pressure sink.

Appendix D

Gas Cap Effect Simulation Data Set and Results, Commercial Plant Utilization and Detailed Plant Bitumen Forecasts and Undiscounted Costs for Athabasca McMurray

```
** SOURCE DATA SET: ATHABASCA MCMURRAY CASE STUDY - BASE CASE
** CMG STARS SIMULATION
**
** No Gas Cap (Base Case Run)
** 3D run assuming a Dead Oil @ Reservoir Conditions
** Model Dimensions: 549 m x 500 m x 24 m
** 500 m Length Horizontal Wells and 24 m of Pay above the Producer Wells
** Initial Reservoir Pressure = 1800 kPa
** Full Scale Pattern Simulation with 3 Well Pairs (Well Pair 1 assumes perfect
symmetry)
** Inter-Well Distance is 90 m and Injector/Producer Vertical Spacing is 4 m
** Grid Block thickness is variable in i-direction (115 - 2 m, 63 - 5 m and 2 -
2 m grid thickness),
** j-direction consists of two slabs - j1 is 100 m and the poorer j2 is 400 m an
d k-direction consists of a
** constant 2 m thickness
** Input and Output Units are SI; and time basis is days
**
** ==============  INPUT/OUTPUT  ========================

*filename *index-in 'Athabasca_Base_NonDep.irf' *main-results-in

*title1 'Joint ADOE-EUB SAGD Study'
*title2 'Case Study: Athabasca McMurray'
*title3 'Pattern Simulation'

**restart

*maxerror 1
*wrst *time

*prntorien  2  0
*outprn *grid *pres *temp *sw *so *sg *x *y
*outprn *well *brief
*wsrf *grid *time
*outsrf *grid *pres *temp *sw *so *sg *x *y

** ==========  GRID AND RESERVOIR DEFINITION ==========

*grid *cart 100 2 12

*kdir *up

*di *ivar 115*2.0 63*5.0 2*2.0

*dj *jvar   100.  400.

*dk *kvar 12*2.0

*vamod 2 0.5 1.0 0.5 0.5 *9p 1.0 1.0
*vatype *ivar 2 179*1

*dtop *con 140.0
```

```
*por *ijk
1:100  1  1:7      0.35
1:100  1  8:12     0.30
1:100  2  1:3      0.35
1:100  2  4        0.30
1:100  2  5        0.35
1:100  2  6        0.30
1:100  2  7:8      0.35
1:100  2  9:12     0.30

*permi *ijk
1:100  1  1:7      10000
1:100  1  8:12     2000
1:100  2  1:3      10000
1:100  2  4        2000
1:100  2  5        10000
1:100  2  6        2000
1:100  2  7:8      10000
1:100  2  9:12     2000

*permj *ijk
1:100  1  1:7      10000
1:100  1  8:12     2000
1:100  2  1:3      10000
1:100  2  4        2000
1:100  2  5        10000
1:100  2  6        2000
1:100  2  7:8      10000
1:100  2  9:12     2000

*permk *ijk
1:100  1  1:7      5000
1:100  1  8:12     200
1:100  2  1:3      2500
1:100  2  4        200
1:100  2  5        2500
1:100  2  6        200
1:100  2  7:8      2500
1:100  2  9:12     200

*cpor 7.0e-6 *prpor 100.0

*rockcp 2.390e6
*cpc    17.0
*thconr 1.469e5
*thconw 1.469e5
*thcono 1.469e5
*thcong 1.469e5

*hlossprop *overbur 2.390e6 1.469e5 *hlosst 7.0 *hlosstdiff 0.1
*hlossprop *underbur 2.390e6 2.333e5 *hlosst 7.0 *hlosstdiff 0.1
```

```
** ================  FLUID DEFINITIONS  ===================

*model 3 3 2

*compname       'WATER'       'OIL'         'CH4'
**          ------------------------------------
*cmm              0            0.5         0.01604
*pcrit            0            0           4600.00
*tcrit            0            0            -82.55

*molden           0            2020.0        0
*cp               0            6.84e-7       0
*ct1              0            7.85e-4       0
*ct2              0            0             0

*kv1              0             0            0
*kv2              0             0            0
*kv3              0             0            0
*kv4              0             0            0
*kv5              0             0            0

*cpl1             0             1000.0       67.2
*cpg1             0             841.0        35.2
*hvapr            0             1346.0       0

*visctable

**  Temp
    10.0          0             0.17e7       0
    20.0          0             0.319e6      0
    40.0          0             0.223e5      0
    60.0          0             3073.0       0
    80.0          0              680.6       0
   100.0          0              212.63      0
   120.0          0               85.54      0
   140.0          0               41.57      0
   160.0          0               23.32      0
   180.0          0               14.60      0
   200.0          0                9.96      0
   220.0          0                7.26      0
   240.0          0                5.59      0
   260.0          0                4.49      0
   280.0          0                3.73      0
```

```
** ==================  ROCK-FLUID DATA  ================

*rockfluid

*rpt 1

*swt

**  Sw          Krw          Krow
** ------------------------------
   0.1500      0.0000       0.9920
   0.2000      0.200e-3     0.9790
   0.2500      0.160e-2     0.9500
   0.3000      0.550e-2     0.7200
   0.3500      0.130e-1     0.6000
   0.4000      0.254e-1     0.4700
   0.4500      0.440e-1     0.3500
   0.5000      0.698e-1     0.2400
   0.5500      0.1040       0.1650
   0.6000      0.1480       0.0930
   0.6500      0.2040       0.0700
   0.7000      0.2710       0.0400
   0.7500      0.3520       0.0150
   0.8000      0.4470       0.0000
   0.8500      0.5590       0.0000
   0.9000      0.6870       0.0000
   0.9500      0.8340       0.0000
   1.0000      1.0000       0.0000

*slt

**  Sl          Krg          Krog
** ------------------------------
   0.1500      1.0000       0.0000
   0.2000      0.9500       0.200e-3
   0.2500      0.8400       0.160e-2
   0.3000      0.7200       0.550e-2
   0.3500      0.6000       0.130e-1
   0.4000      0.4700       0.254e-1
   0.4500      0.3500       0.440e-1
   0.5000      0.2400       0.698e-1
   0.5500      0.1650       0.1040
   0.6000      0.930e-1     0.1480
   0.6500      0.750e-1     0.2040
   0.7000      0.450e-1     0.2710
   0.7500      0.270e-1     0.3520
   0.8000      0.200e-1     0.4470
   0.8500      0.100e-1     0.5590
   0.9000      0.500e-2     0.6870
   0.9500      0.0000       0.8340
   1.0000      0.0000       0.9920
```

```
*rpt 2

*swt

**  Sw          Krw         Krow
** ----------------------------
   0.25        0.0         0.95
   0.3         0.0005      0.72
   0.35        0.003       0.6
   0.4         0.009       0.47
   0.45        0.022       0.35
   0.5         0.046       0.24
   0.55        0.081       0.165
   0.6         0.131       0.093
   0.65        0.186       0.07
   0.7         0.257       0.04
   0.75        0.341       0.015
   0.8         0.436       0.
   0.85        0.551       0.
   0.9         0.683       0.
   0.95        0.832       0.
   1.0         1.0         0.

*slt

**  Sl          Krg         Krog
** ----------------------------
   0.25        0.84        0.
   0.3         0.72        0.0005
   0.35        0.6         0.003
   0.4         0.47        0.009
   0.45        0.35        0.022
   0.5         0.24        0.046
   0.55        0.165       0.081
   0.6         0.093       0.131
   0.65        0.075       0.186
   0.7         0.045       0.257
   0.75        0.027       0.341
   0.8         0.02        0.436
   0.85        0.01        0.551
   0.9         0.005       0.683
   0.95        0.          0.832
   1.0         0.          0.95
```

```
*rpt 3

*swt

**  Sw          Krw         Krow
** ----------------------------
   0.5         0.          0.24
   0.55        0.01        0.165
   0.6         0.03        0.093
   0.65        0.07        0.07
   0.7         0.12        0.04
   0.75        0.204       0.015
   0.8         0.3         0.
   0.85        0.433       0.
   0.9         0.58        0.
   0.95        0.79        0.
   1.          1.          0.

*slt

**  Sl          Krg         Krog
** ----------------------------
   0.5         0.24        0.
   0.55        0.165       0.002
   0.6         0.093       0.005
   0.65        0.075       0.01
   0.7         0.045       0.02
   0.75        0.027       0.027
   0.8         0.02        0.045
   0.85        0.01        0.075
   0.9         0.005       0.093
   0.95        0.          0.165
   1.          0.          0.24

*krtype *ijk
1:100  1  1:7        1
1:100  1  8:12       2
1:100  2  1:3        1
1:100  2  4          2
1:100  2  5          1
1:100  2  6          2
1:100  2  7:8        1
1:100  2  9:12       2
```

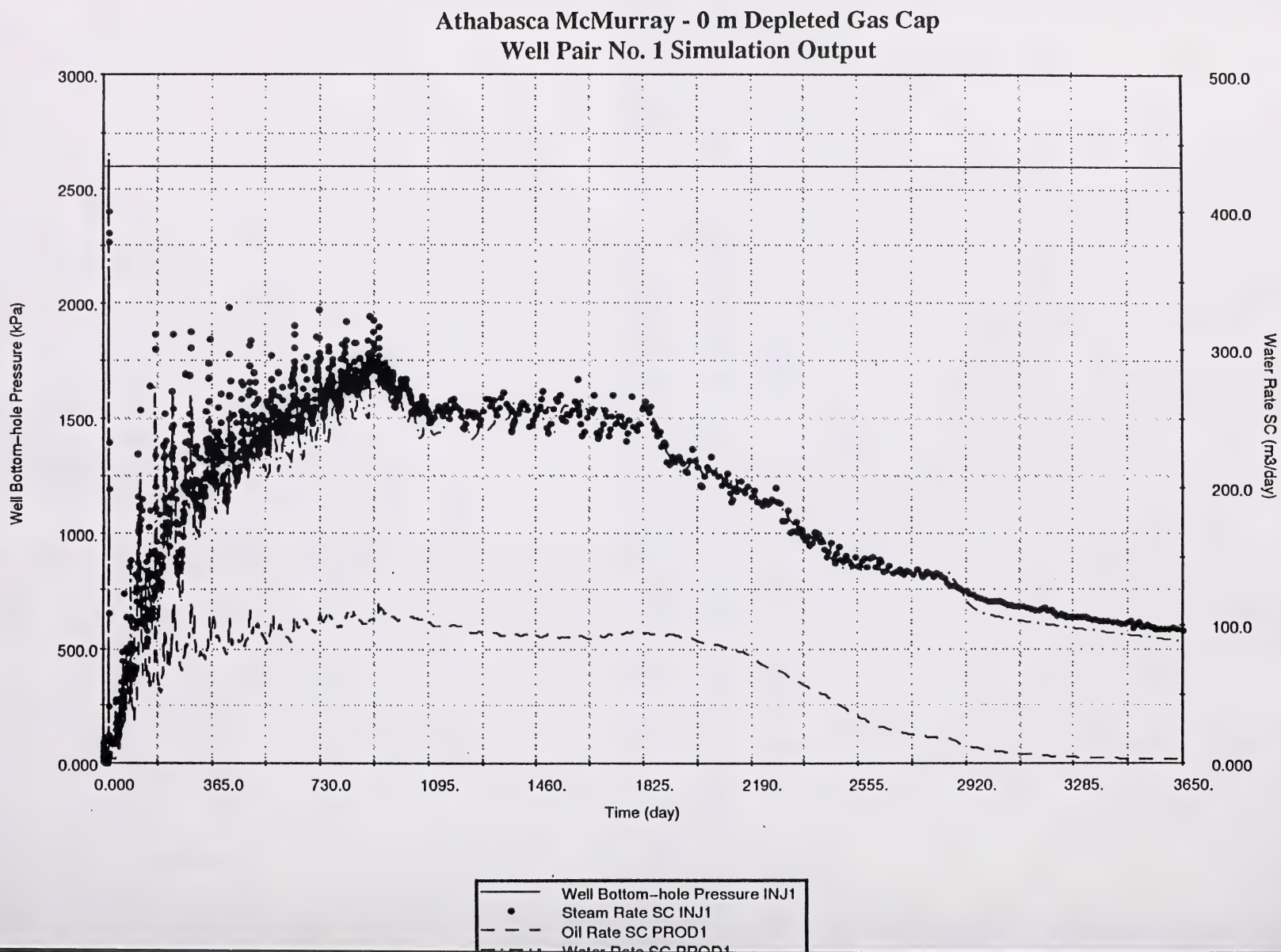
```
** ------------------  INITIAL CONDITIONS  ----------------------

*initial

*pres *con 1000.0

*temp *con 7.0

*sg *ijk  1:180 1:2 1:12  0.

*so *ijk
1:180  1  1:7       0.85
1:180  1  8:12      0.75
1:180  2  1:3       0.85
1:180  2  4         0.75
1:180  2  5         0.85
1:180  2  6         0.75
1:180  2  7:8       0.85
1:180  2  9:12      0.75

*molefrac *oil *con  0.0  1.0
**molefrac *gas *con 0.0  0.0 1. 0.


** ==================  NUMERICAL CONTROL  ======================

*numerical

*aim             *off
*dtmax           15.0
*maxsteps        5000
*north           8
*itermax         60
*unrelax         -1
*sdegree         2
*sorder          rcmrb
*mintemp         1
*minpres         50
*norm            *press 400.0
                 *satur 0.2
                 *temp 50.       *y      0.2     *x      0.2

*converge        *press 30.
                 *satur 0.04     *y      .04     *x      .04
                 *temp   3.0

*pvtoscmax       4
```

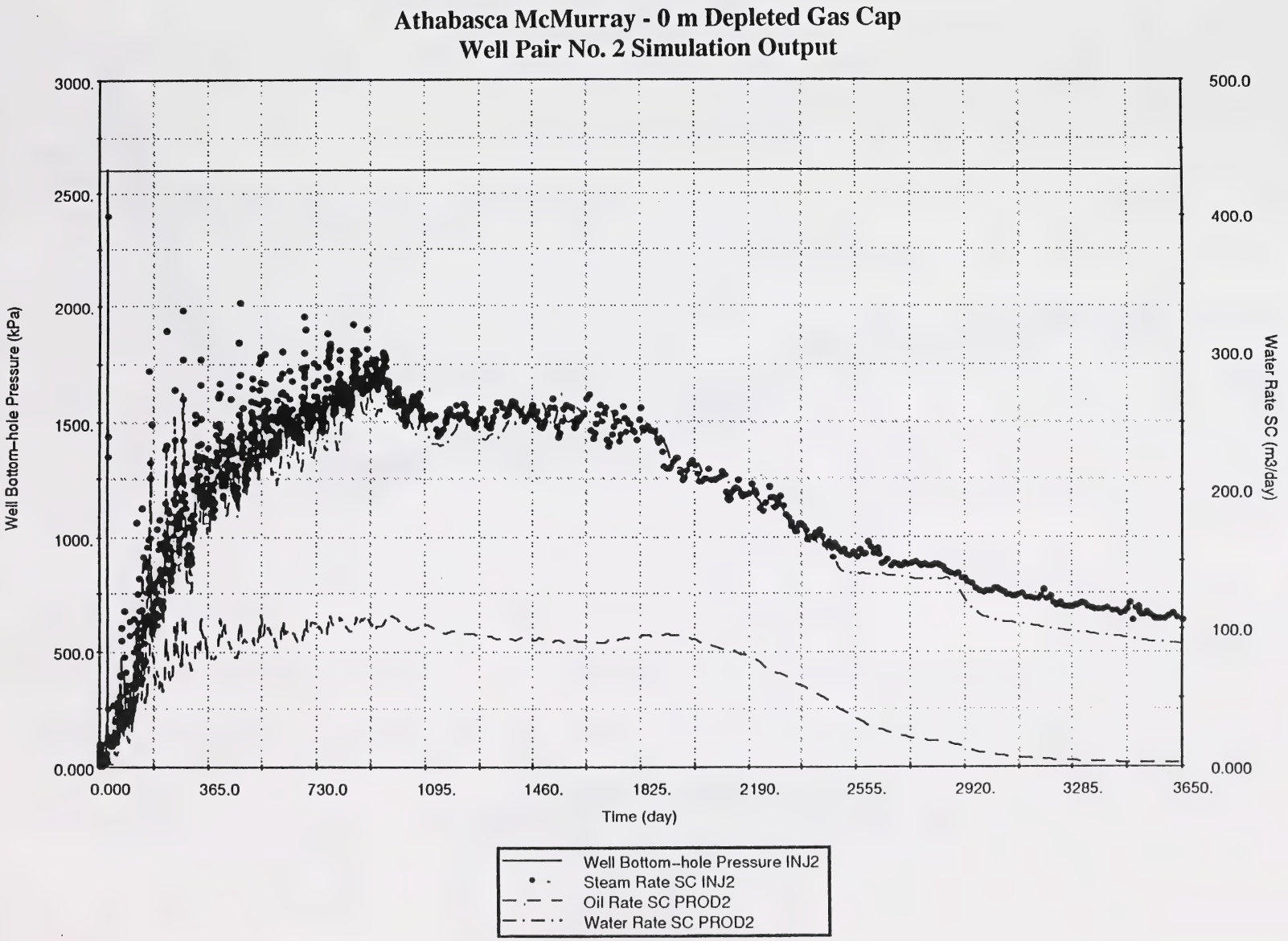
```
** ==================  RECURRENT DATA  ==========================

*run
*date 2000 1 1  *dtwell 1.0e-2

*well 1 'INJ1'  *frac   0.5
*injector *mobweight 1
*tinjw 226.0  *qual 0.95
*operate *max *bhp 2600.0
*operate *max *water 400.
*operate *max *bhp 2600.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 1
1  1:2  3
*uhtr *ijk
1:1  1:2  3     0.110e9
*tmpset *ijk
1:1  1:2  3     226.0

*well 2 'PROD1'  *frac   0.5
*producer 2
*operate *min *bhp 2250.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 2
1  1:2  1
*uhtr *ijk
1:1  1:2  1     0.110e9
*tmpset *ijk
1:1  1:2  1     210.0

*well 3 'INJ2'
*injector *mobweight 3
*tinjw 226.0  *qual 0.95
*operate *max *bhp 2600.0
*operate *max *water 400.
*operate *max *bhp 2600.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 3
46  1:2  3
*uhtr *ijk
46:46  1:2  3     0.110e9
*tmpset *ijk
46:46  1:2  3     226.0

*well 4 'PROD2'
*producer 4
*operate *min *bhp 2250.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 4
46  1:2  1
*uhtr *ijk
46:46  1:2  1     0.110e9
*tmpset *ijk
46:46  1:2  1     210.0
```

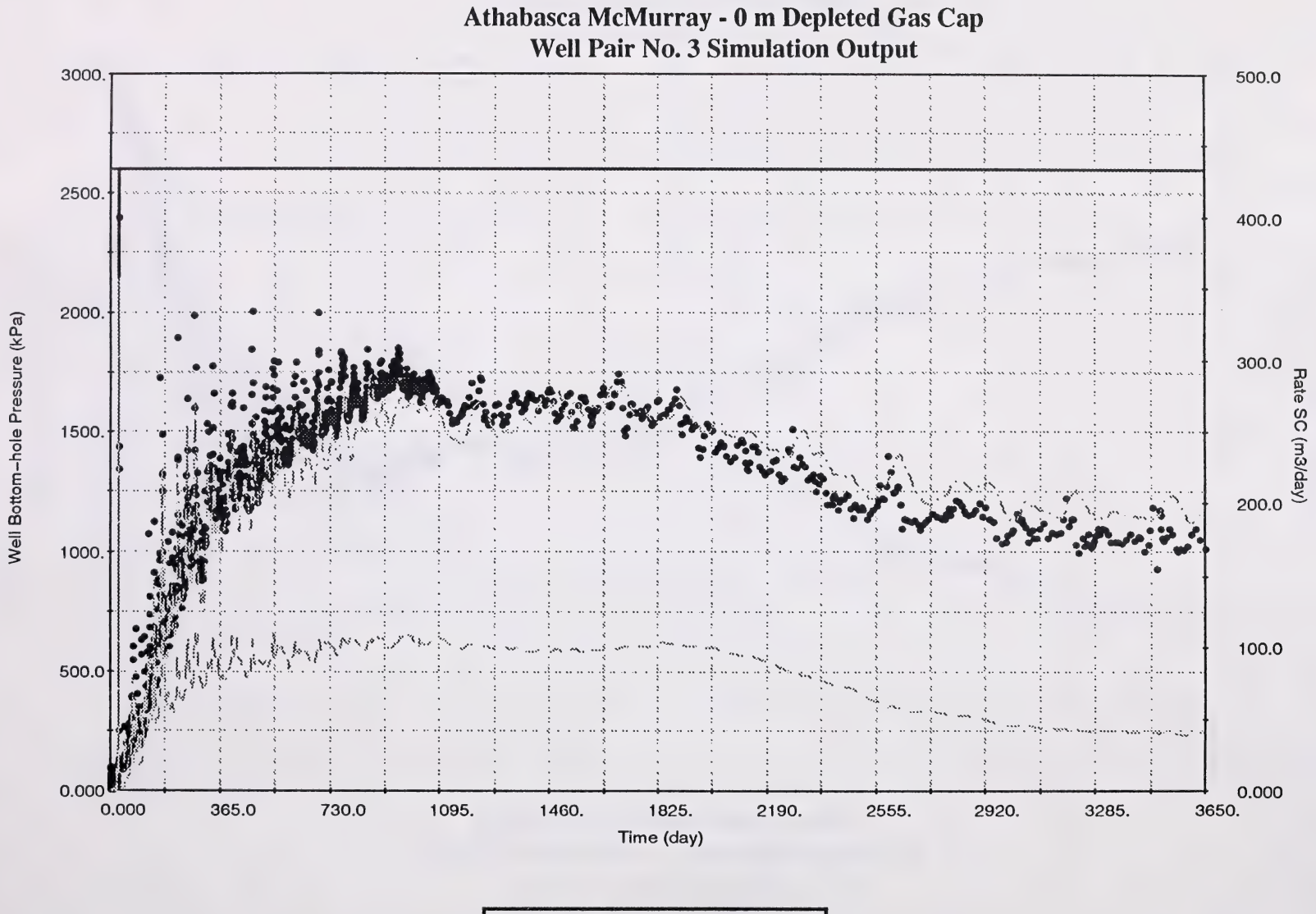
```
*well 5 'INJ3'
*injector *mobweight 5
*tinjw 226.0  *qual 0.95
*operate *max *bhp 2600.0
*operate *max *water 400.
*operate *max *bhp 2600.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 5
91  1:2  3
*uhtr *ijk
91:91  1:2  3     0.110e9
*tmpset *ijk
91:91  1:2  3     226.0

*well 6 'PROD3'
*producer 6
*operate *min *bhp 2250.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 6
91  1:2  1
*uhtr *ijk
91:91  1:2  1     0.110e9
*tmpset *ijk
91:91  1:2  1     218.0

**well 7 'GAS'    *frac    0.5
**producer 7
**operate *min *bhp 1800.
**operate *max *gas 10000.
**operate *min *bhp 1800.
**geometry *j 0.110 0.249 1.0 0.0
**perf *geo 7
**180  1:2  14

*group  'INJ1' 'INJ2' 'INJ3' *attachto 'INJECTION'
*group  'PROD1' 'PROD2' 'PROD3' *attachto 'PRODUCTION'
```

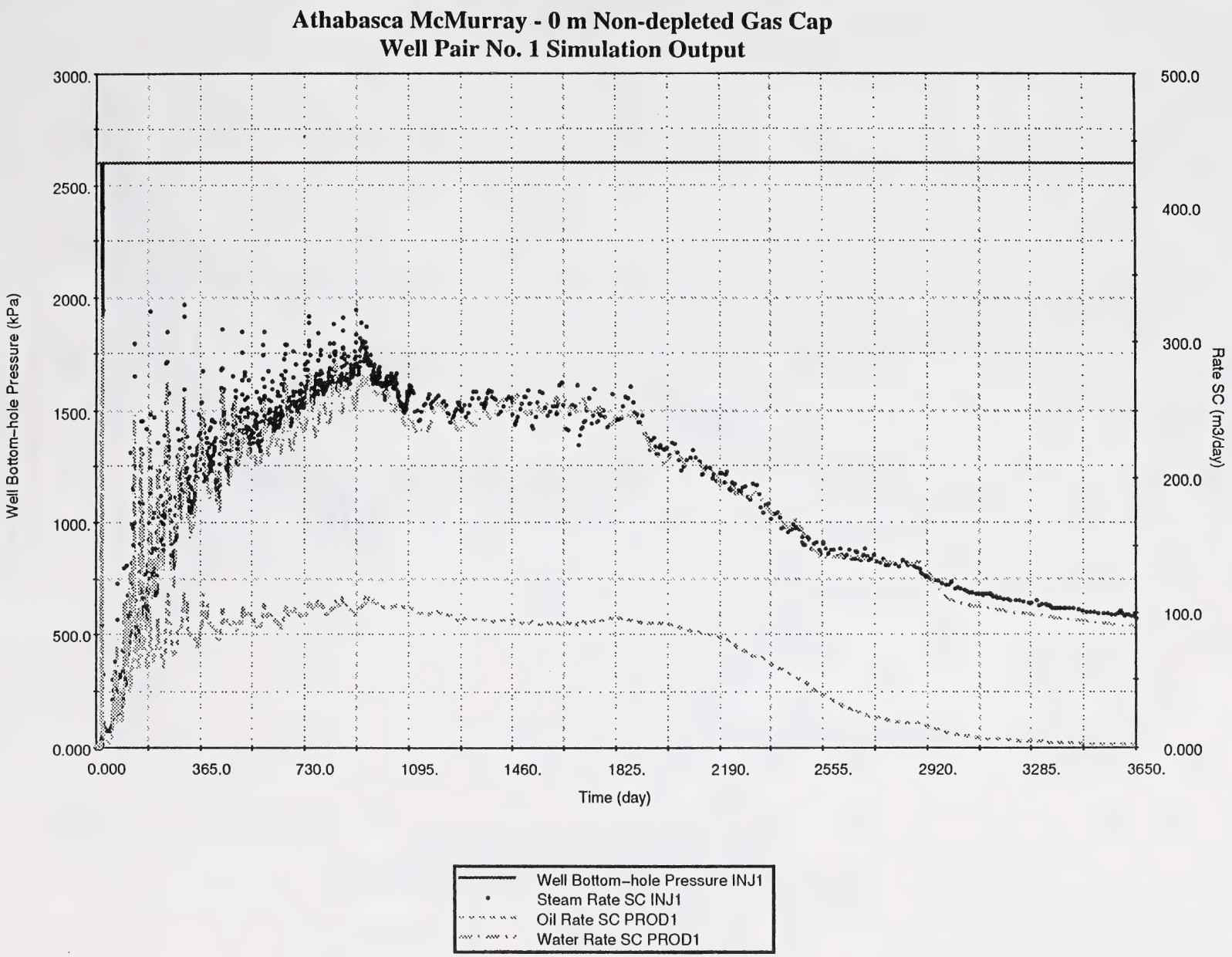
```
*dtmax 1.0

*time 10.0
*time 20.0
*time 36.5    **0.1 yrs
*time 50.
*time 60.
*time 70.
*time 90.
*time 100.
*time 120.
*time 150.
*time 180.
*time 210.
*time 250.
*time 300.
*time 350.
*time 365.0

*uhtr *ijk 1 1 4 0
*uhtr *ijk 1 1 1 0

*uhtr *ijk 46 1 4 0
*uhtr *ijk 46 1 1 0

*uhtr *ijk 91 1 4 0
*uhtr *ijk 91 1 1 0

*time 400.
*time 420.
*time 438     **1.2 yrs
*time 455.
*time 530.
*time 584.    **1.6 yrs
*time 657.    **1.8 yrs
*time 730.              **2.0 yrs
*time 803.    **2.2 yrs
*time 876.    **2.4 yrs
*time 949.    **2.6 yrs
*time 1022.   **2.8 yrs
*time 1095.             **3.0 yrs
*dtmax          15.0
*time 1168.   **3.2 yrs
*time 1241.   **3.4 yrs
*time 1314.   **3.6 yrs
*time 1387.   **3.8 yrs
*time 1460.              **4.0 yrs
*time 1533.   **4.3 yrs
*time 1565.               **3 yrs operating time
*time 1606.   **4.4 yrs
*time 1679.   **4.6 yrs
*time 1752.   **4.8 yrs
*time 1825.             **5.0 yrs
*time 1898.   **5.2 yrs
*time 1971.   **5.4 yrs
*time 2044.   **5.6 yrs
*time 2117.   **5.8 yrs
*time 2190.             **6.0 yrs
```

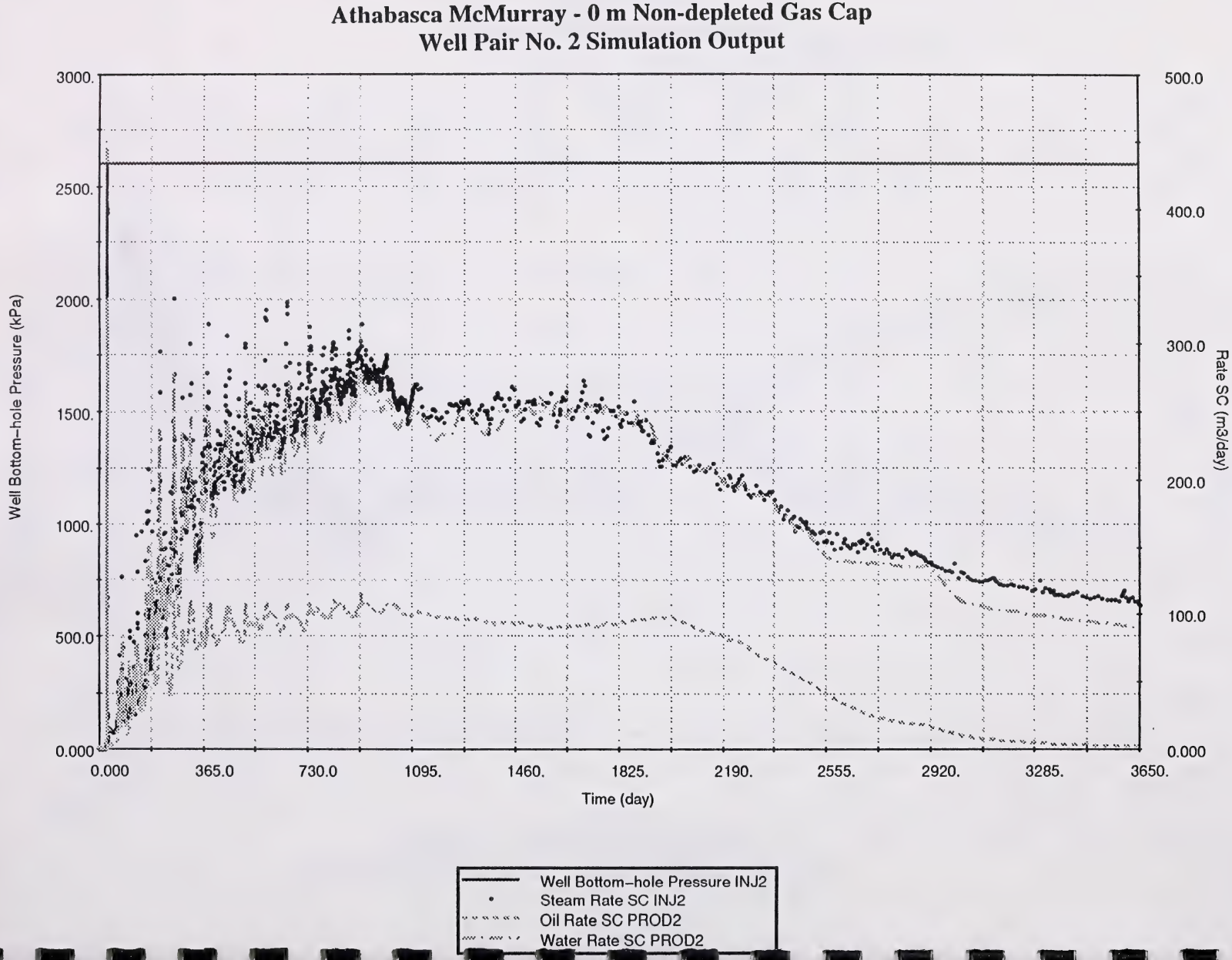
```
*time 2263.    **6.2 yrs
*time 2336.    **6.4 yrs
*time 2409.    **6.6 yrs
*time 2482.    **6.8 yrs
*time 2555.              **7.0 yrs
*time 2628.    **7.2 yrs
*time 2701.    **7.4 yrs
*time 2774.    **7.6 yrs
*time 2847.    **7.8 yrs
*time 2920.              **8.0 yrs
*time 2993.    **8.2 yrs
*time 3066.    **8.4 yrs
*time 3139.    **8.6 yrs
*time 3212.    **8.8 yrs
*time 3285.              **9.0 yrs
*time 3358.    **9.2 yrs
*time 3431.    **9.4 yrs
*time 3504.    **9.6 yrs
*time 3577.    **9.8 yrs
*time 3650.             **10.0 yrs


*stop
```

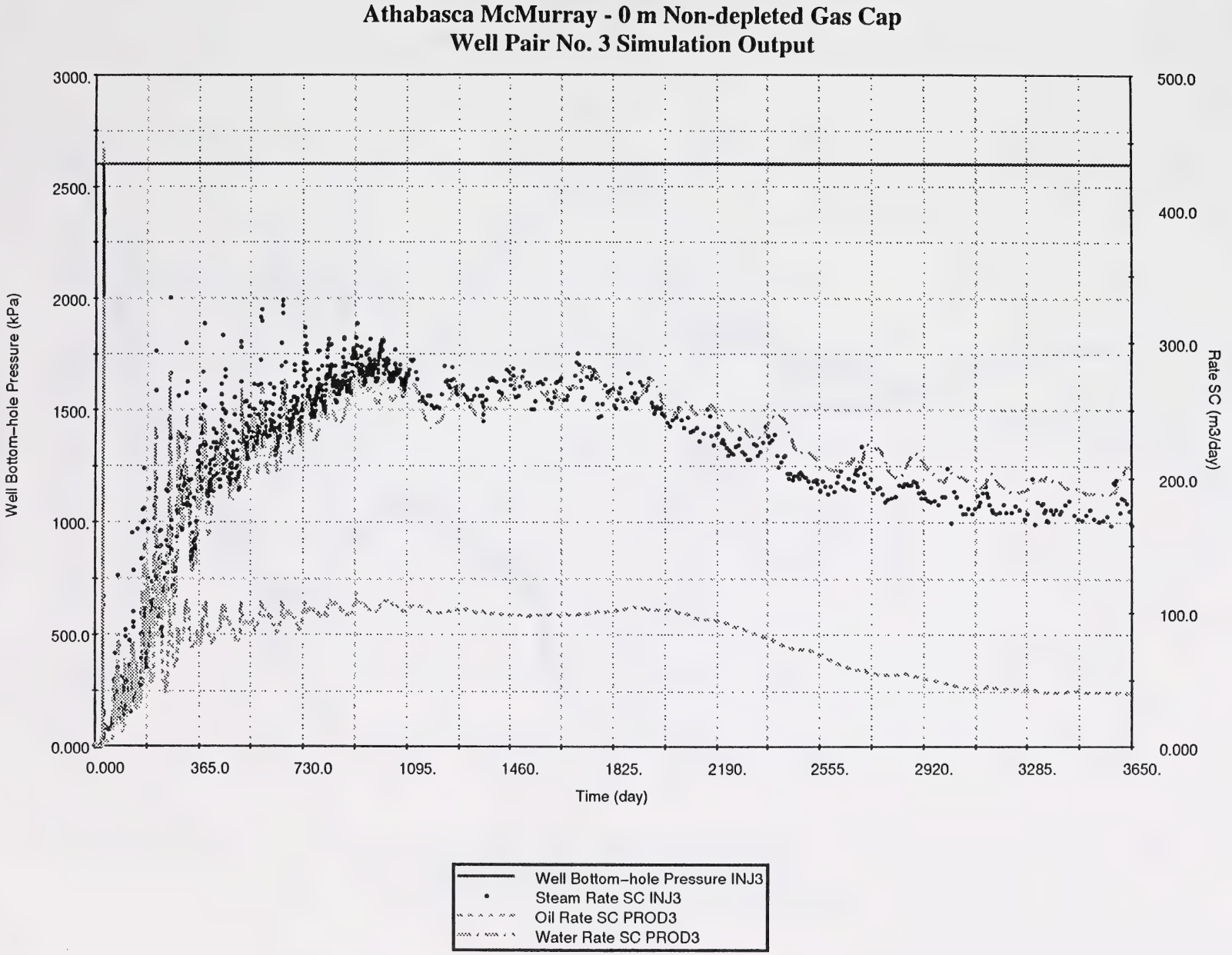

Athabasca McMurray - 0 m Depleted Gas Cap
Well Pair No. 1 Simulation Output
Well Bottom-hole Pressure (kPa)
Water Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ1
Steam Rate SC INJ1
Oil Rate SC PROD1

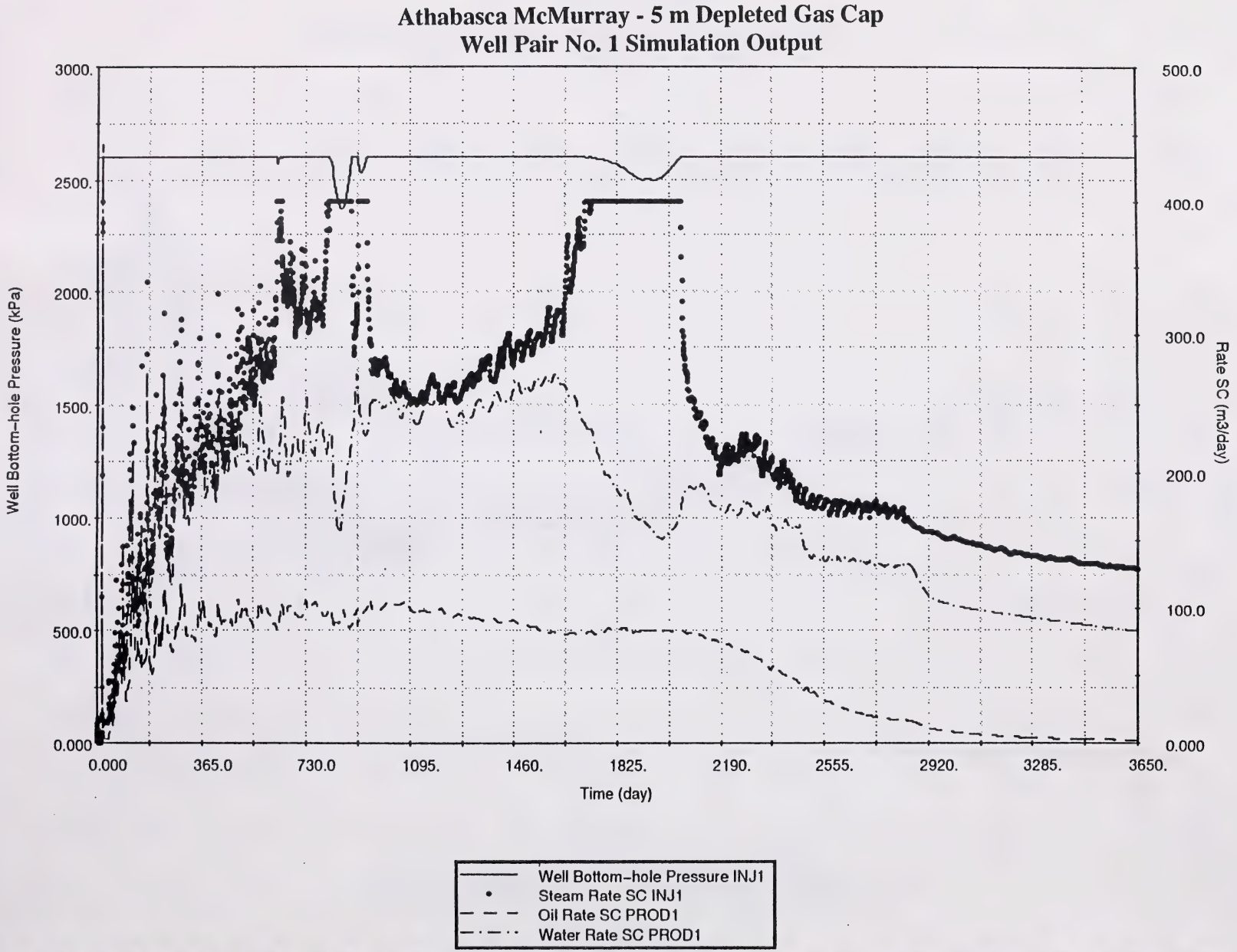

Athabasca McMurray - 0 m Depleted Gas Cap
Well Pair No. 2 Simulation Output
Well Bottom-hole Pressure (kPa)
Water Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ2
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2

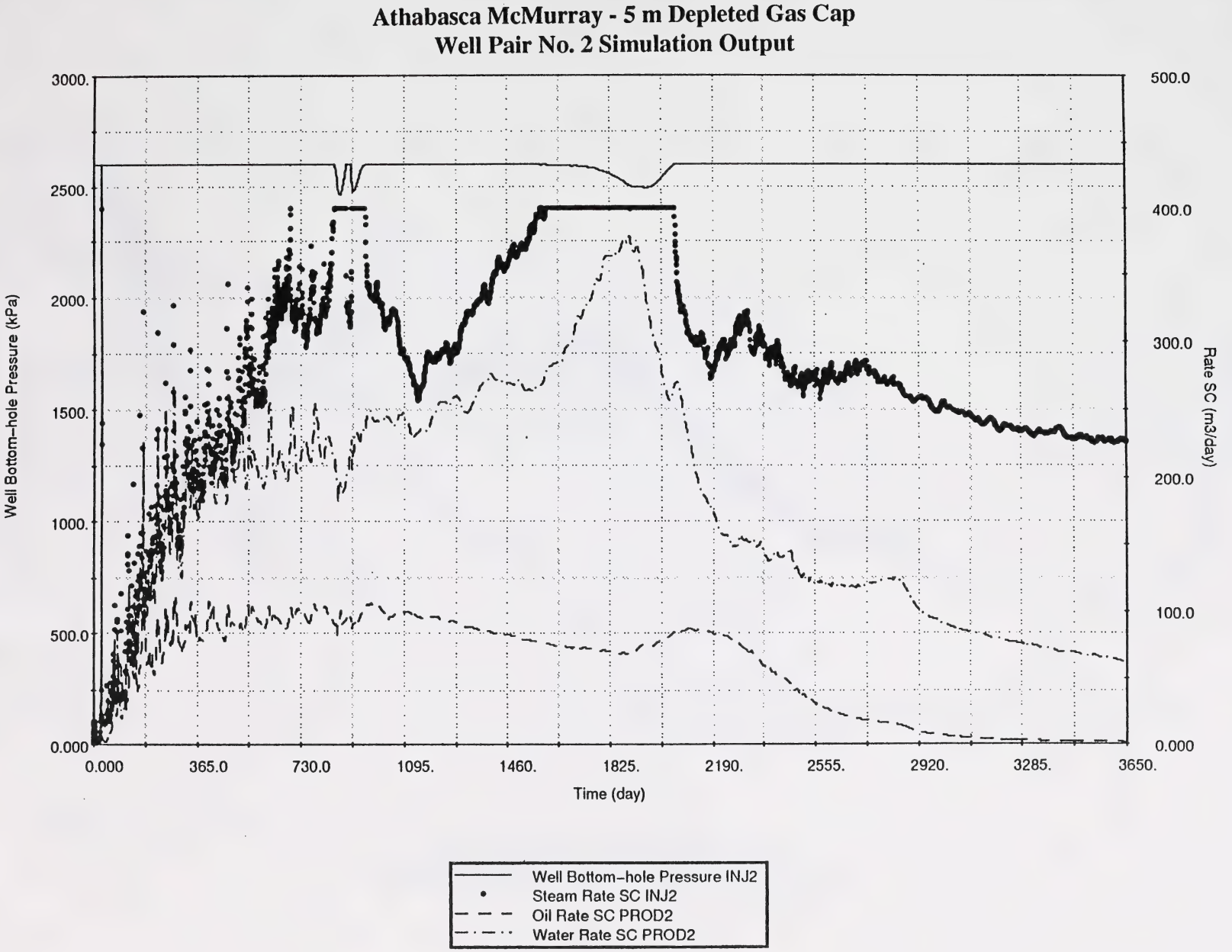

Athabasca McMurray - 0 m Depleted Gas Cap
Well Pair No. 3 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ3
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3

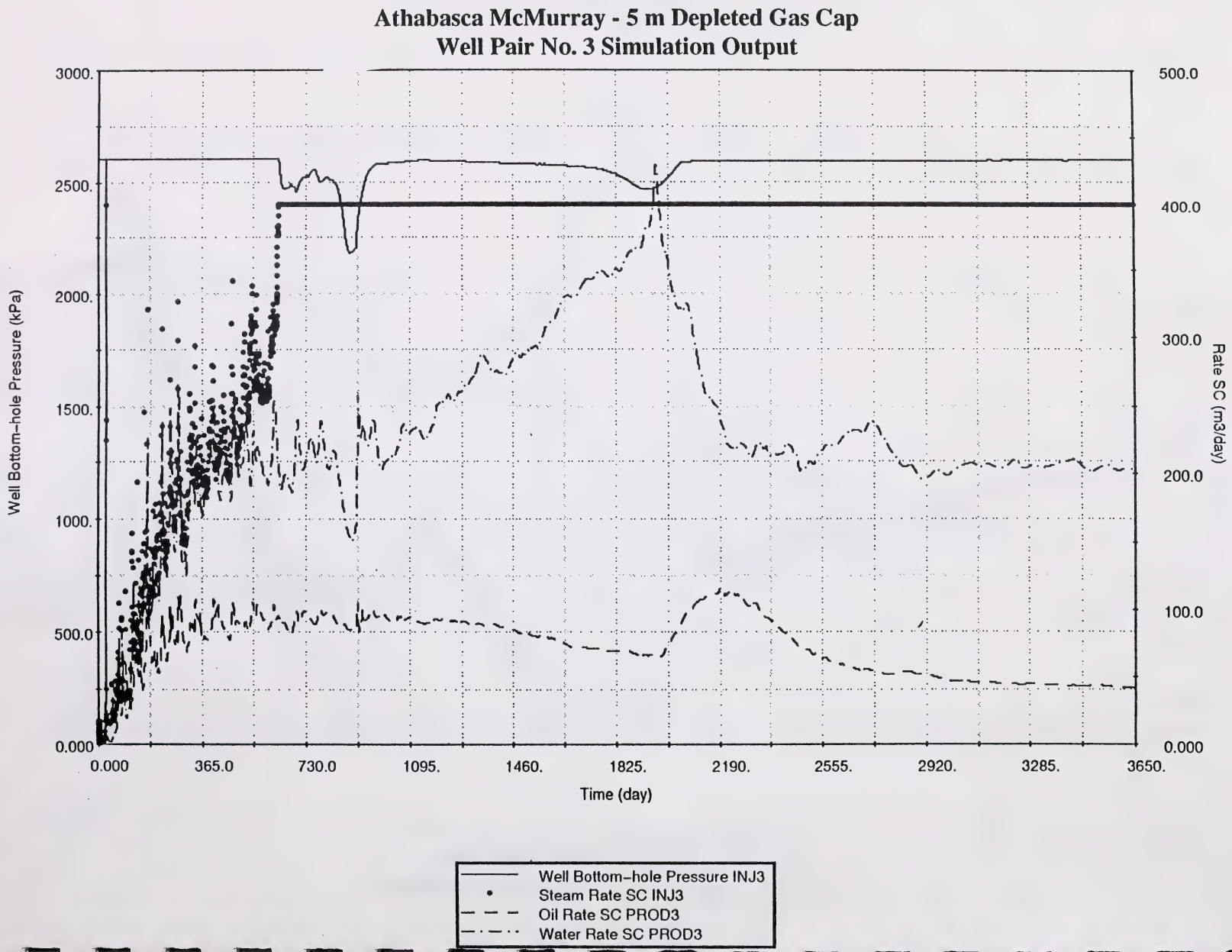

Athabasca McMurray - 0 m Non-depleted Gas Cap
Well Pair No. 1 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ1
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1

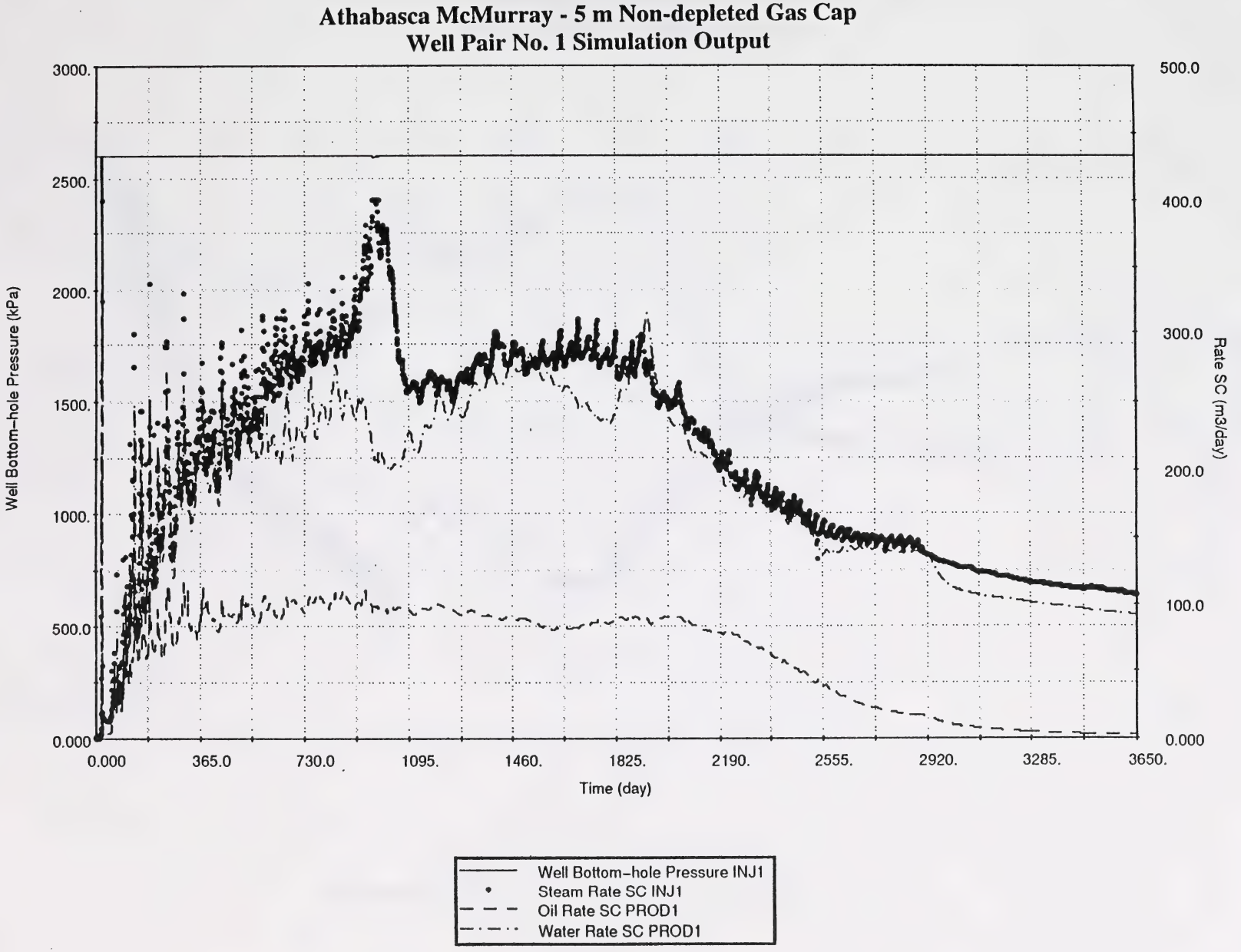

Athabasca McMurray - 0 m Non-depleted Gas Cap
Well Pair No. 2 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ2
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2

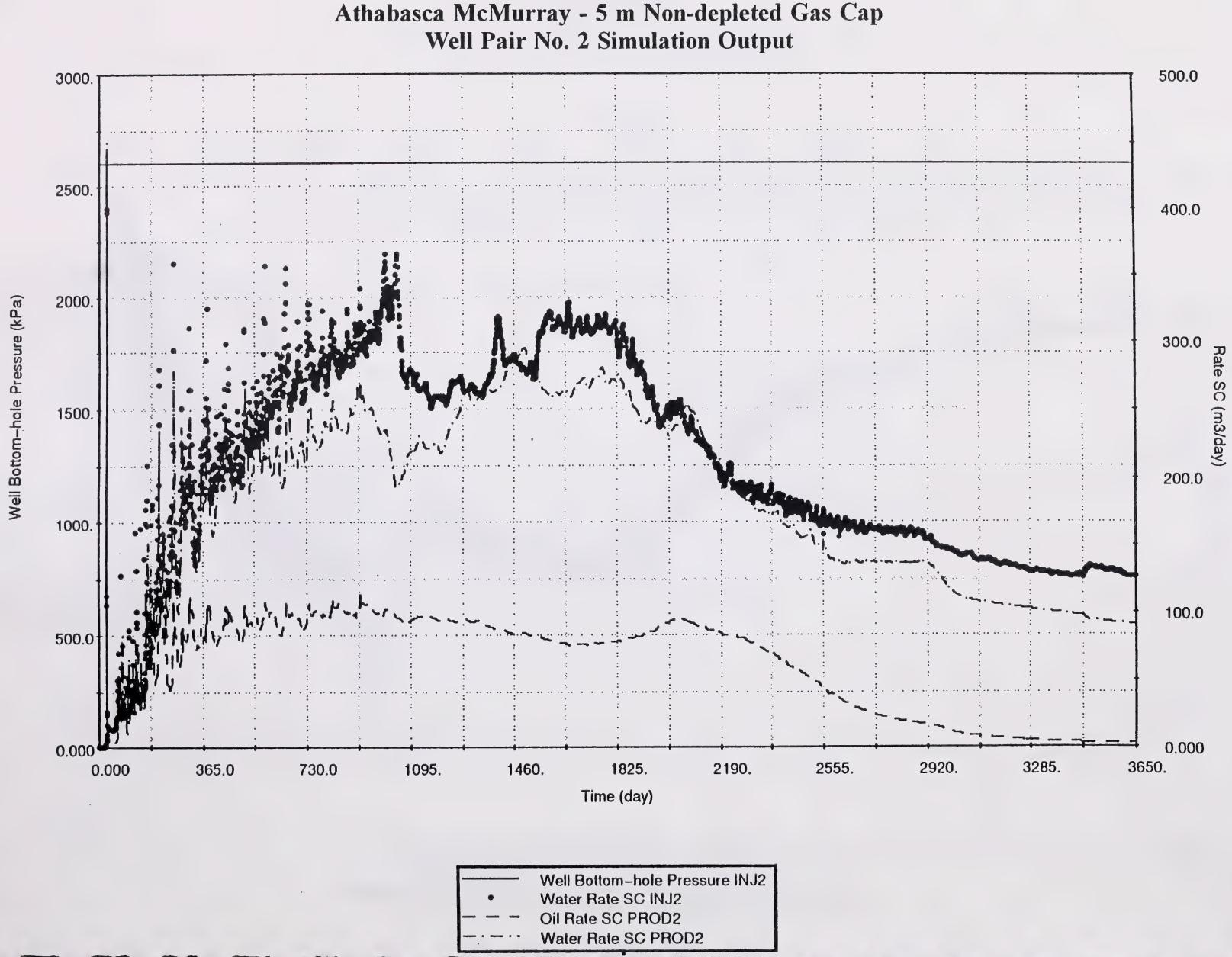

Athabasca McMurray - 0 m Non-depleted Gas Cap
Well Pair No. 3 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ3
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3

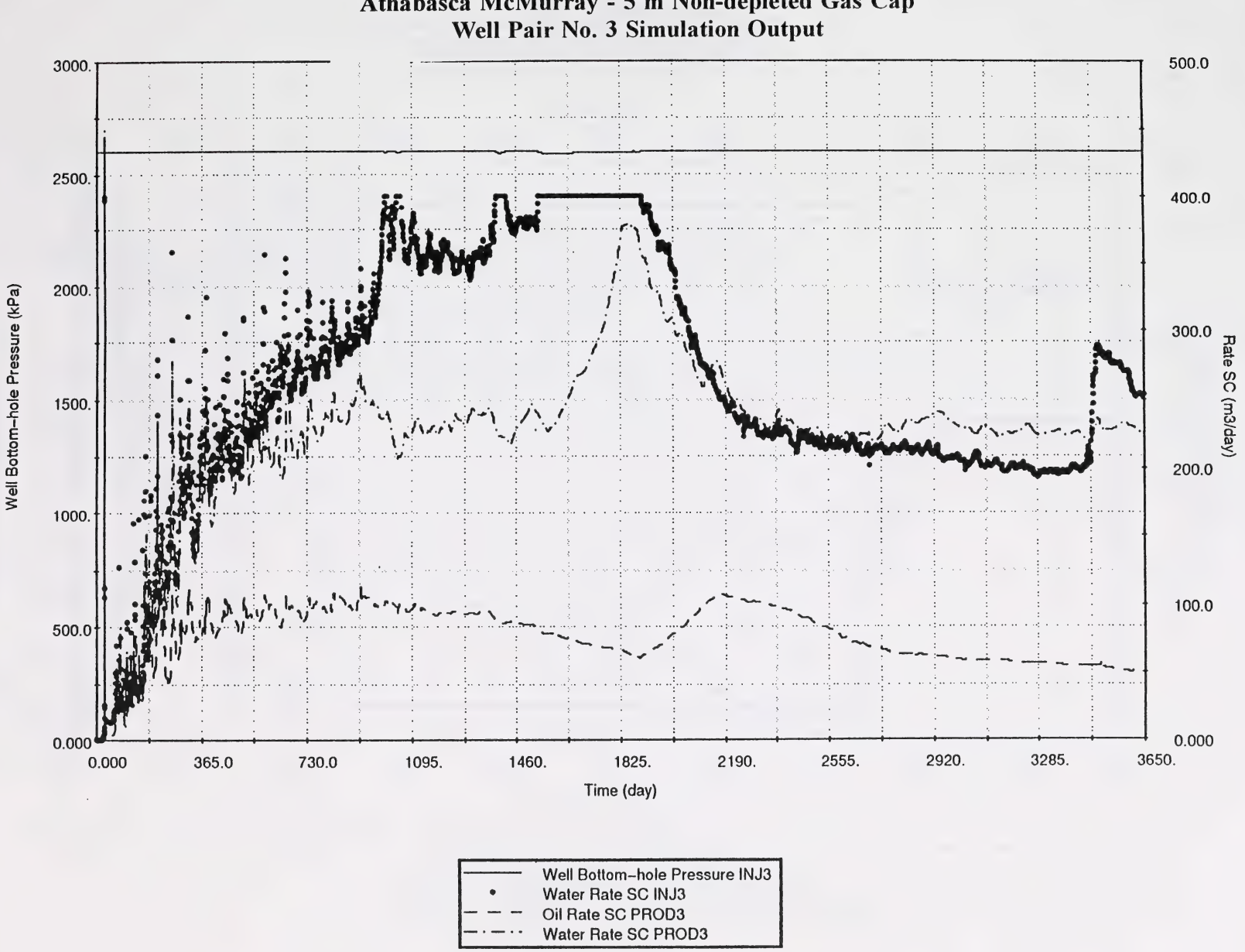

Athabasca McMurray - 5 m Depleted Gas Cap
Well Pair No. 1 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ1
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1

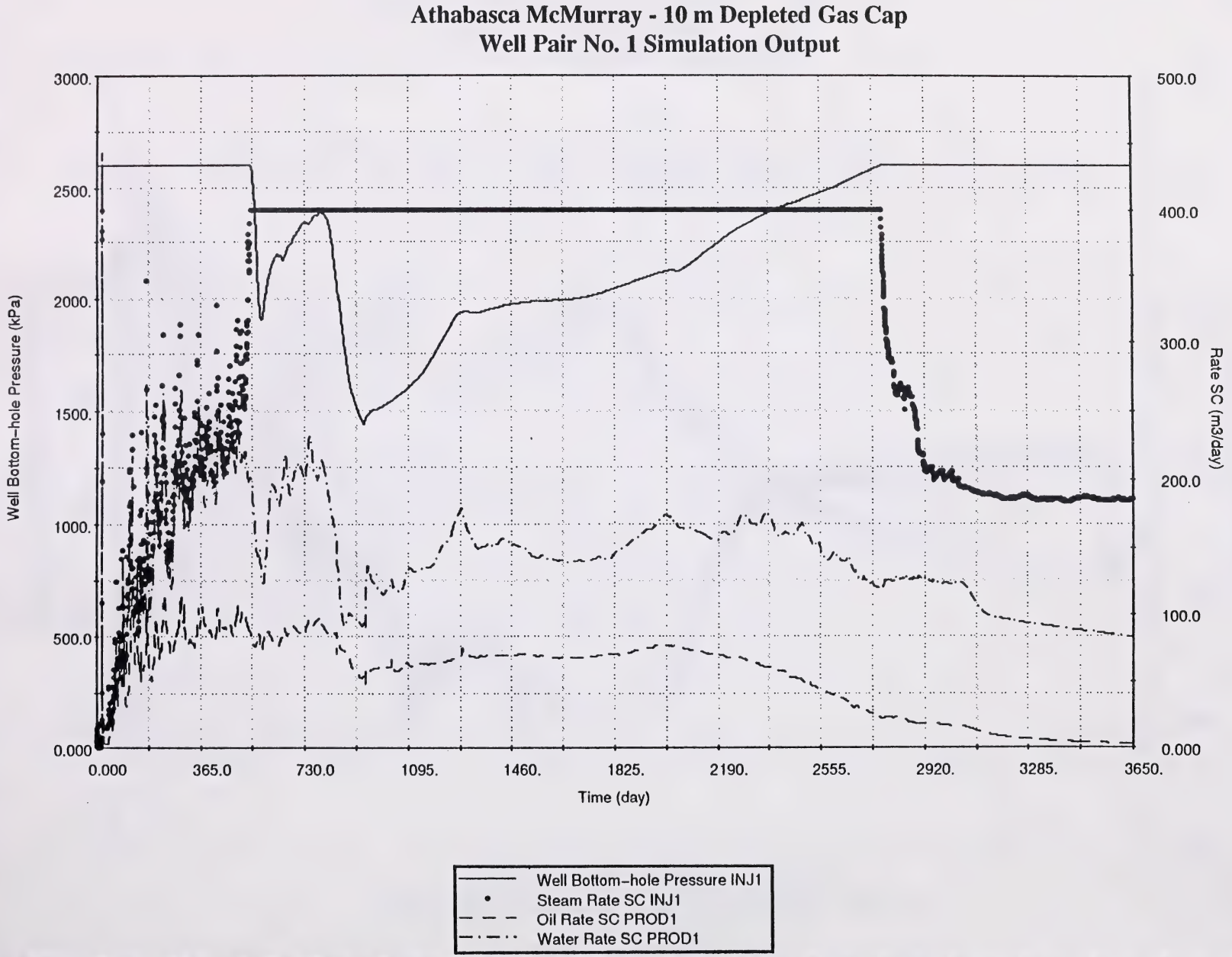

Athabasca McMurray - 5 m Depleted Gas Cap
Well Pair No. 2 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ2
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2

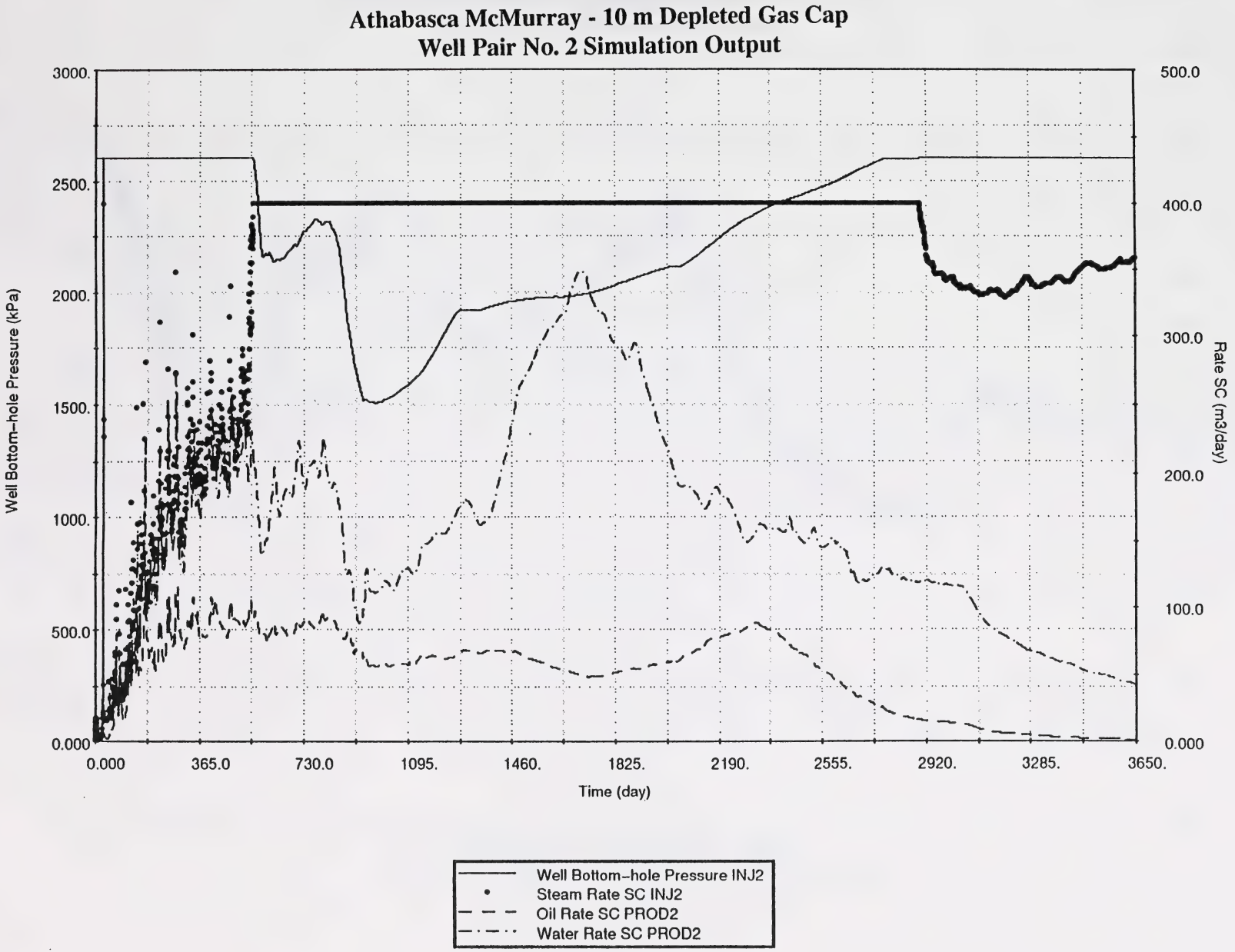

Athabasca McMurray - 5 m Depleted Gas Cap
Well Pair No. 3 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ3
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3

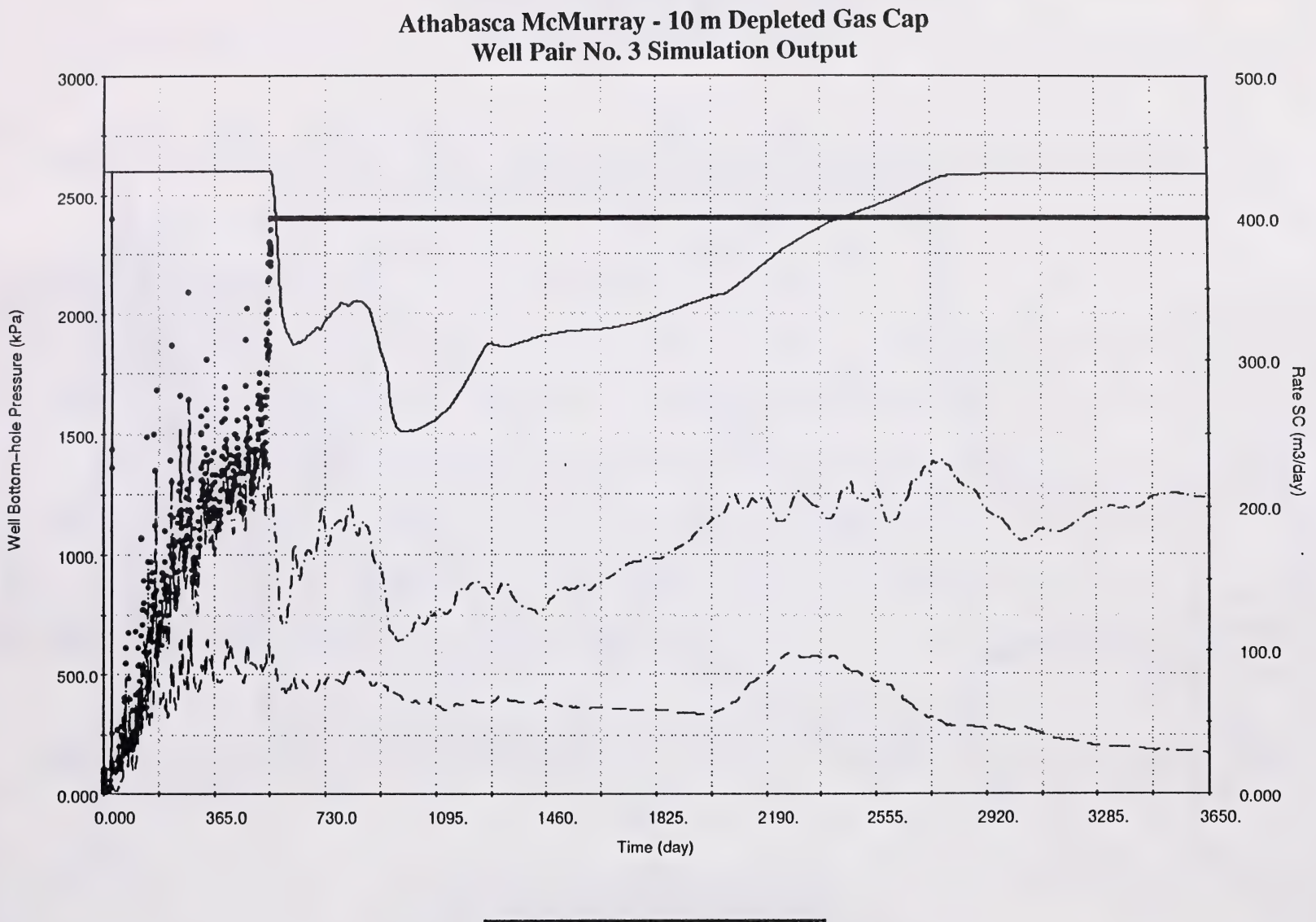

Athabasca McMurray - 5 m Non-depleted Gas Cap
Well Pair No. 1 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ1
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1

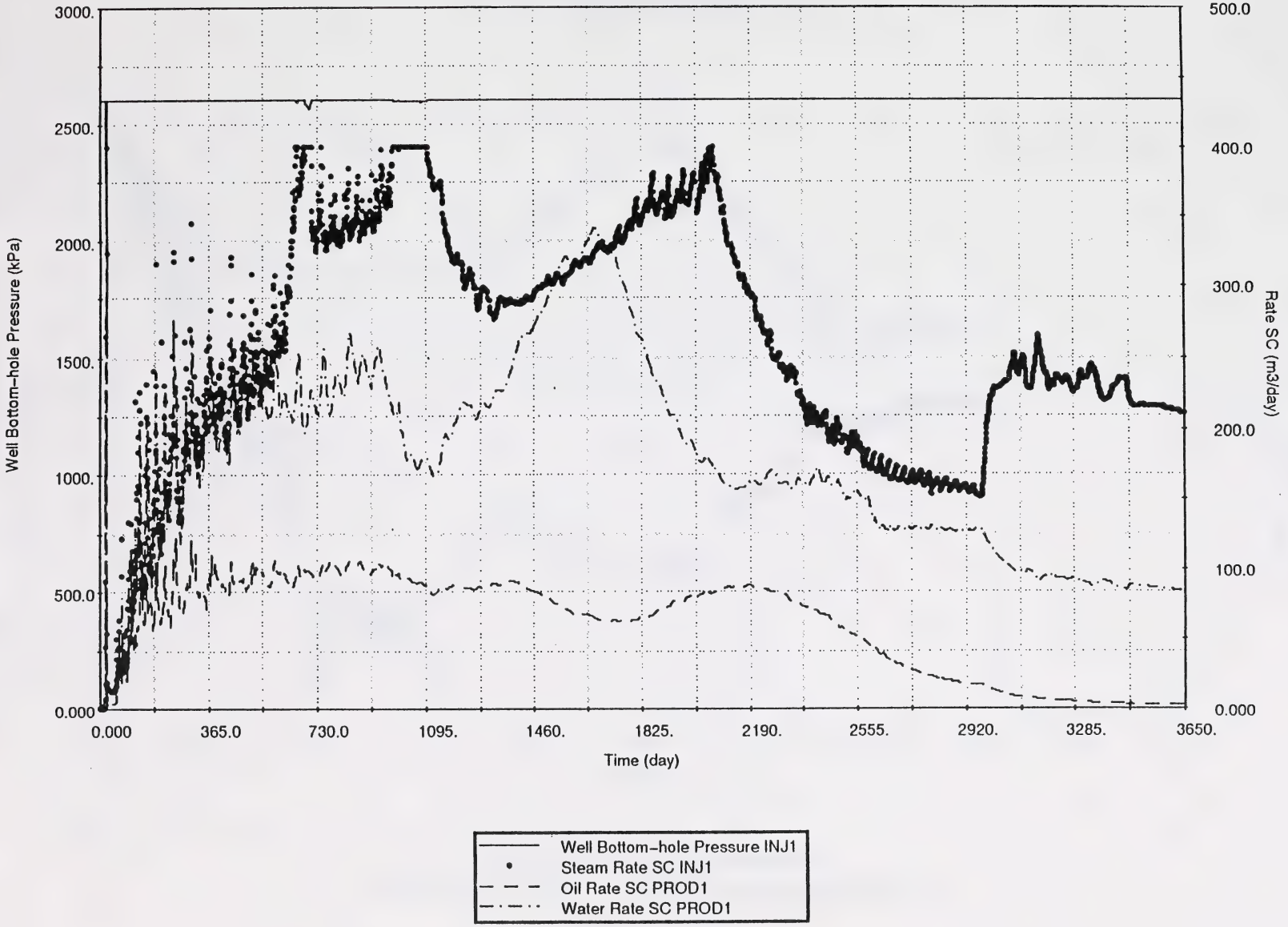

Athabasca McMurray - 5 m Non-depleted Gas Cap
Well Pair No. 2 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ2
Water Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2

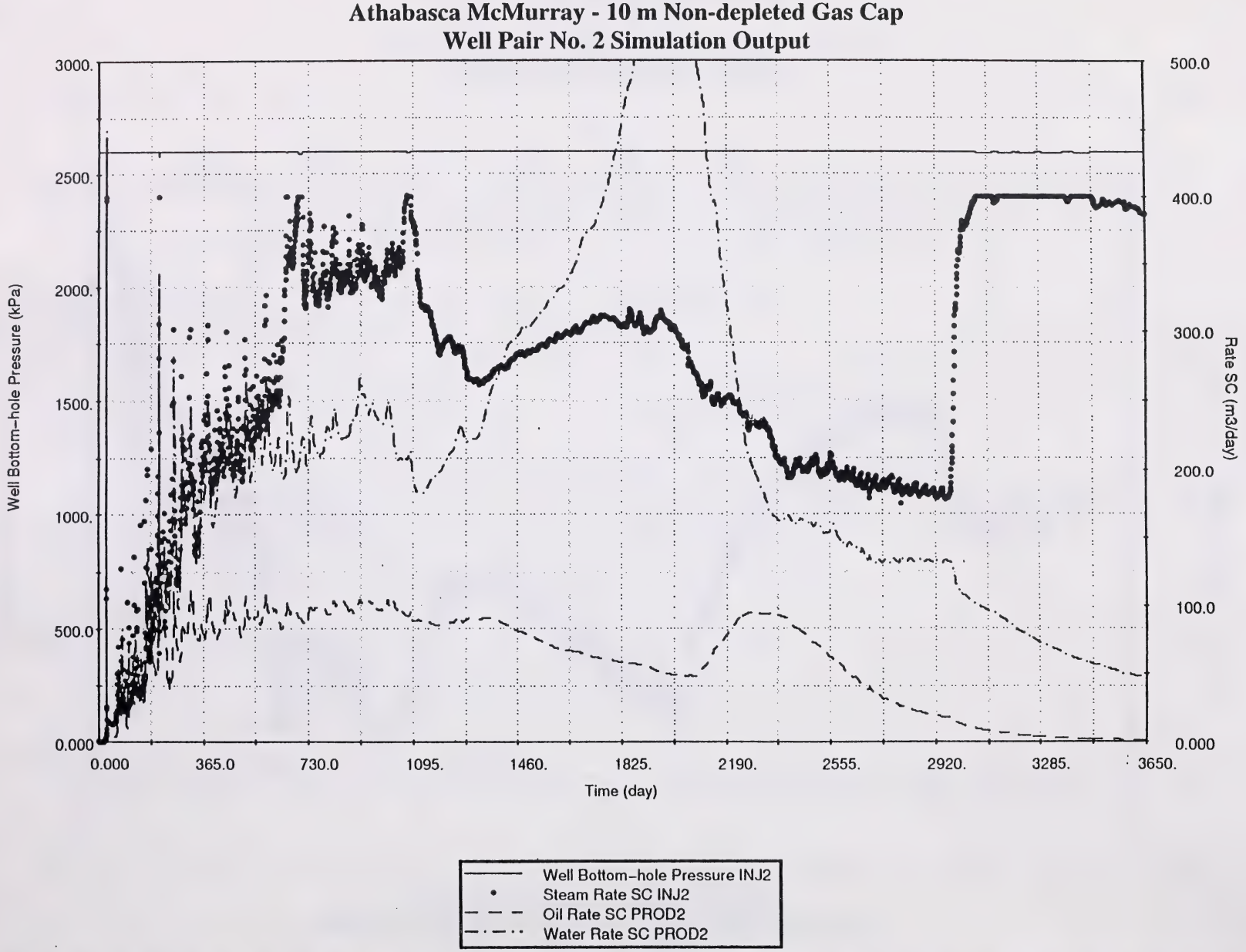

Athabasca McMurray - 5 m Non-depleted Gas Cap
Well Pair No. 3 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ3
Water Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3

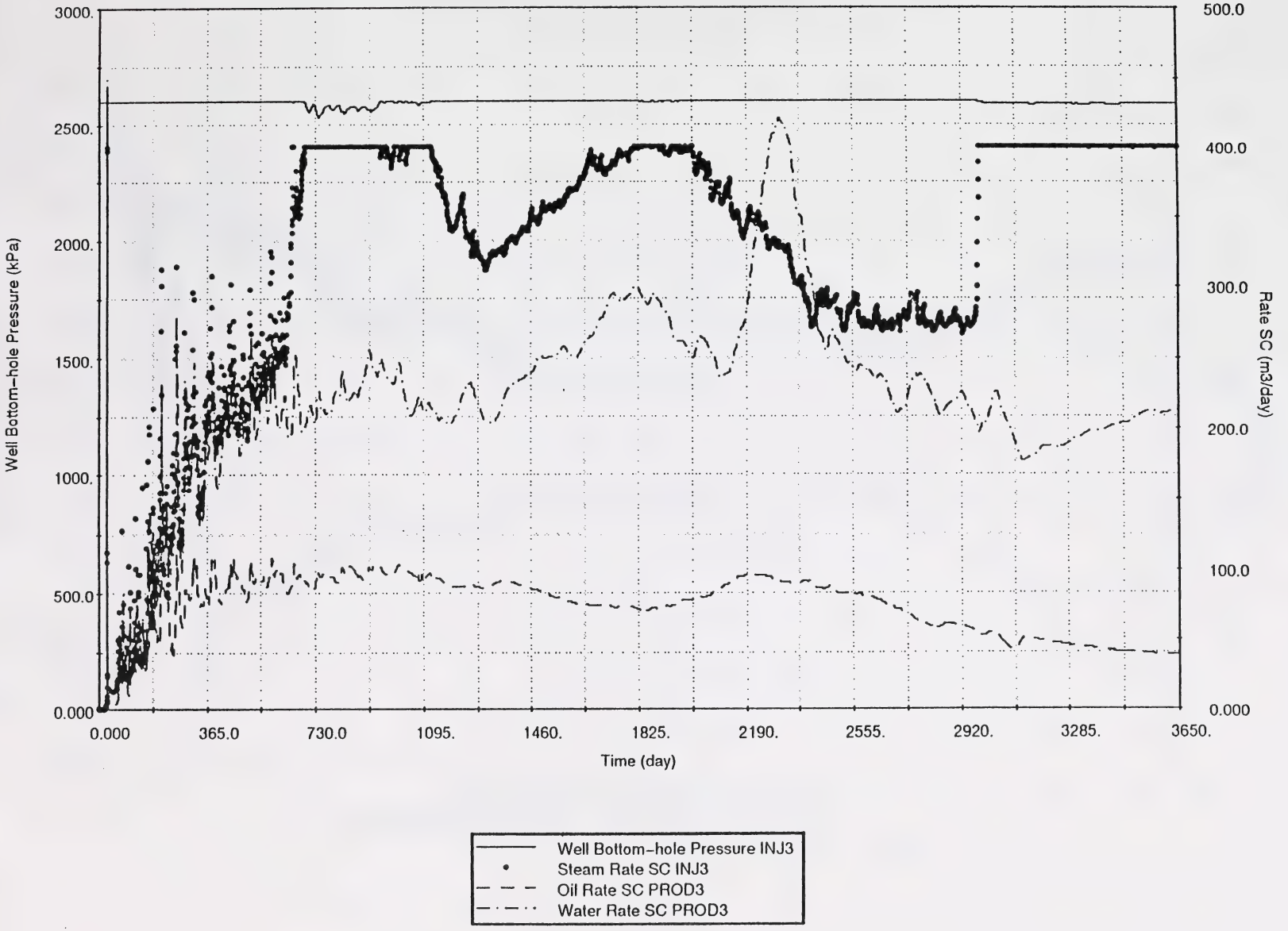

Athabasca McMurray - 10 m Depleted Gas Cap
Well Pair No. 1 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ1
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1

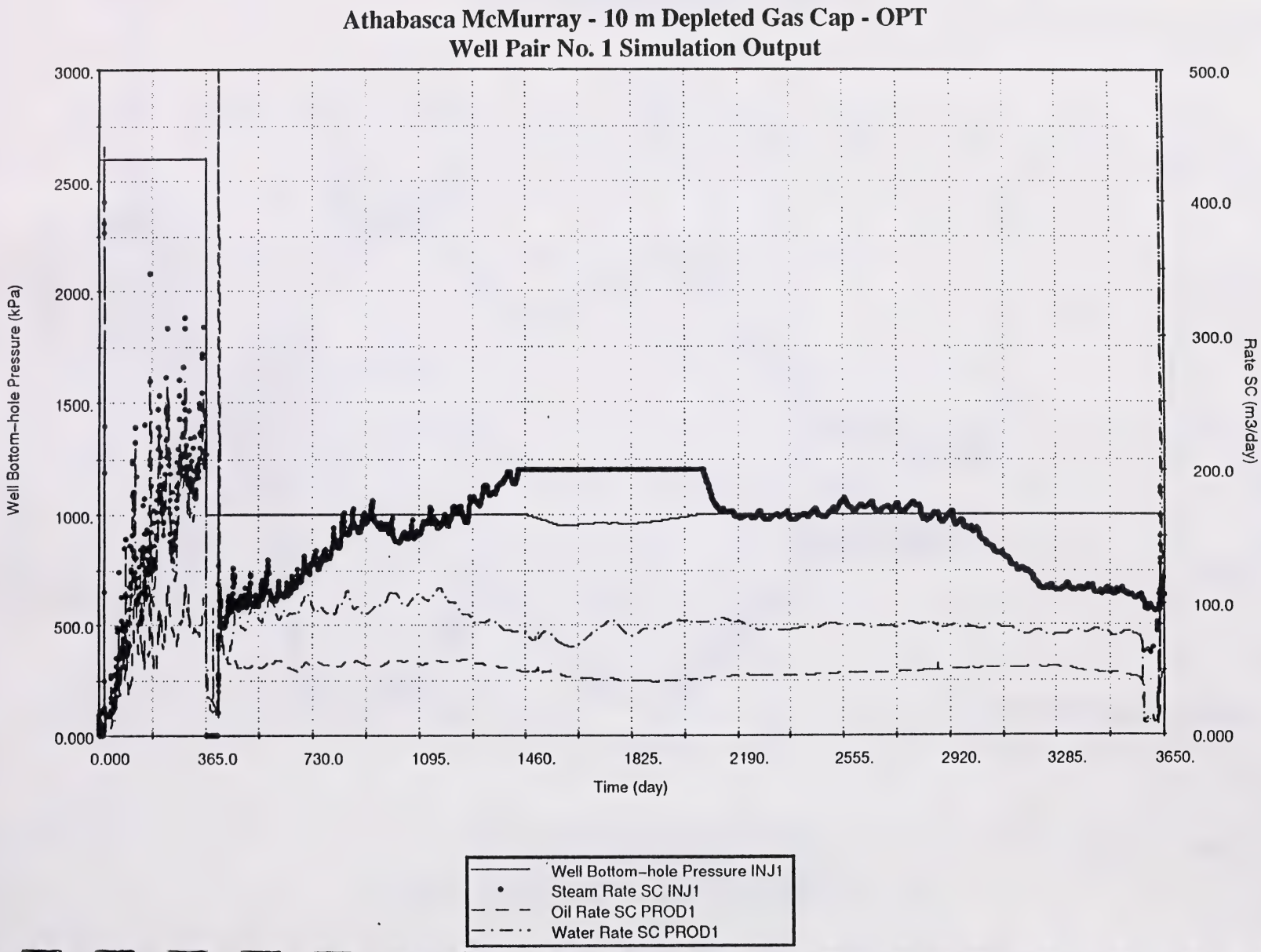

Athabasca McMurray - 10 m Depleted Gas Cap
Well Pair No. 2 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ2
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2

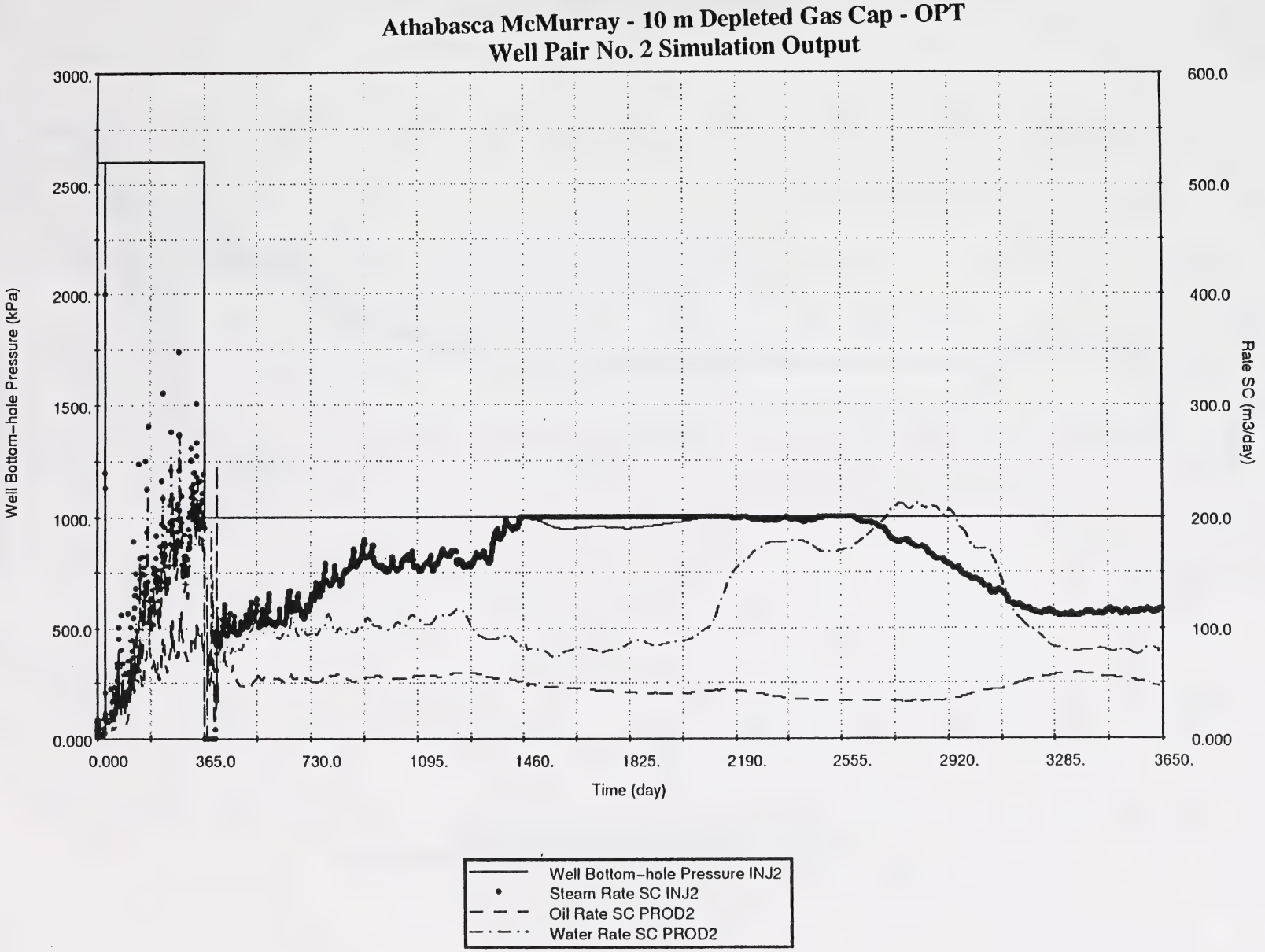

Athabasca McMurray - 10 m Depleted Gas Cap
Well Pair No. 3 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ3
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3

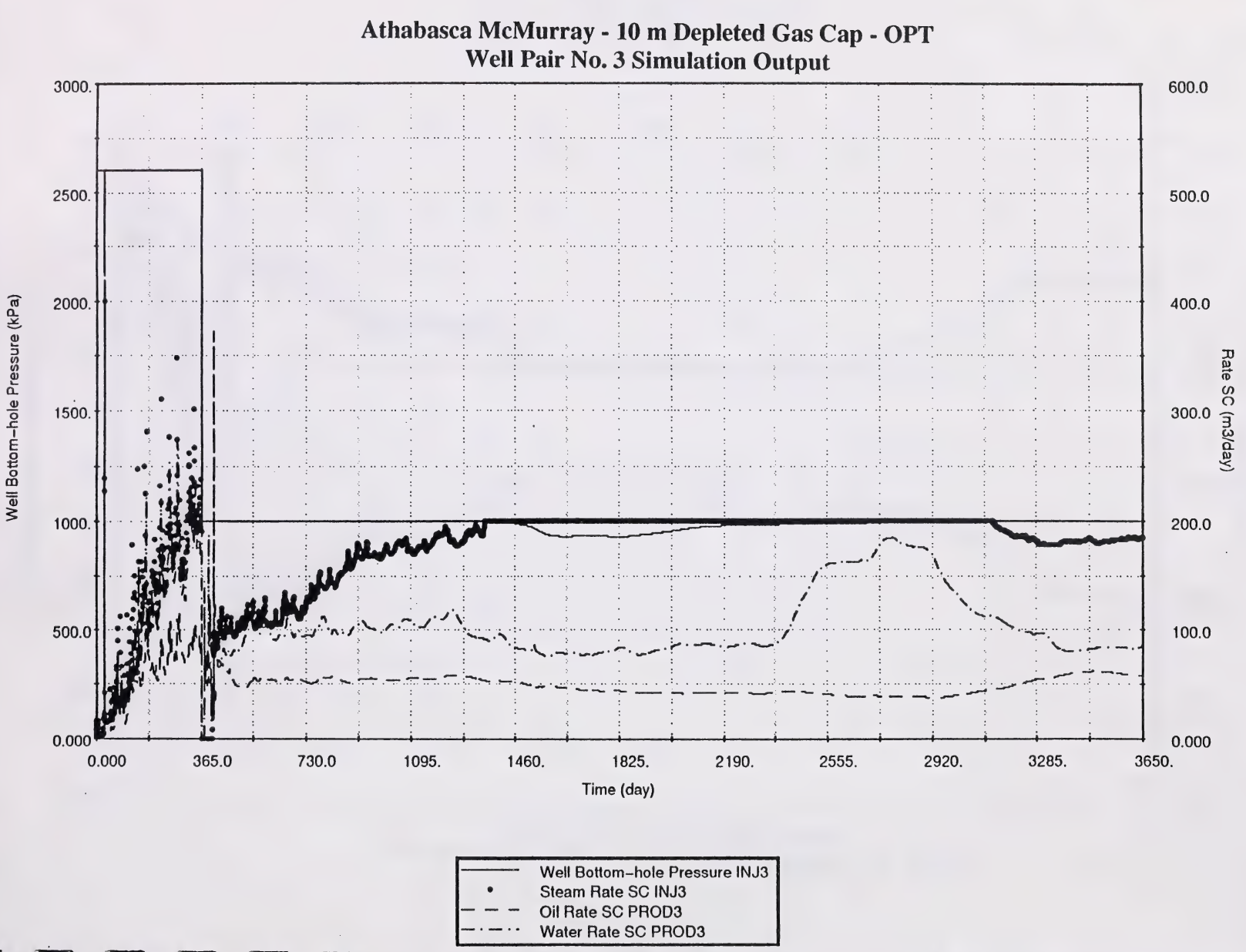

Athabasca McMurray - 10 m Non-depleted Gas Cap
Well Pair No. 1 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ1
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1

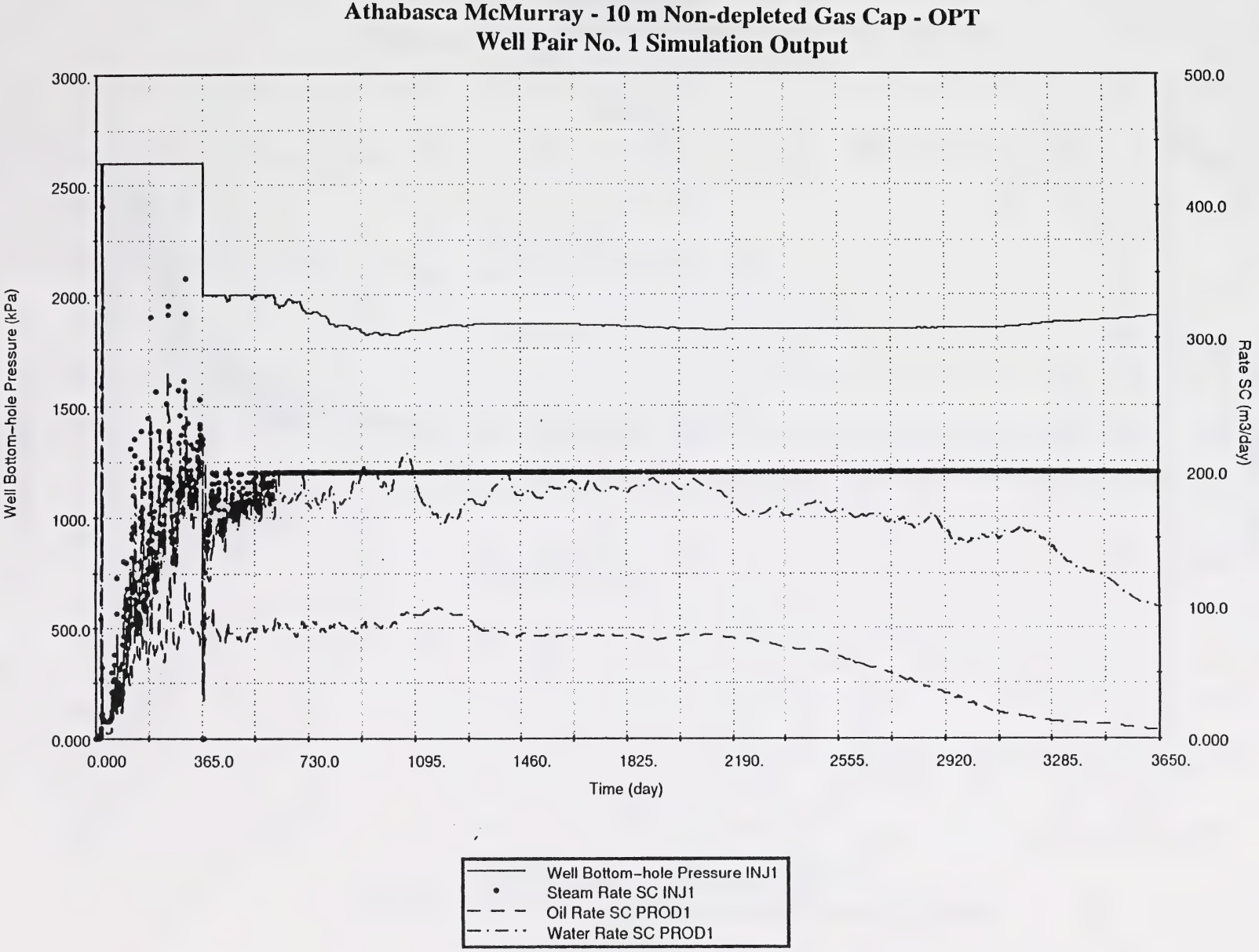

Athabasca McMurray - 10 m Non-depleted Gas Cap
Well Pair No. 2 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ2
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2


Athabasca McMurray - 10 m Non-depleted Gas Cap
Well Pair No. 3 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ3
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3

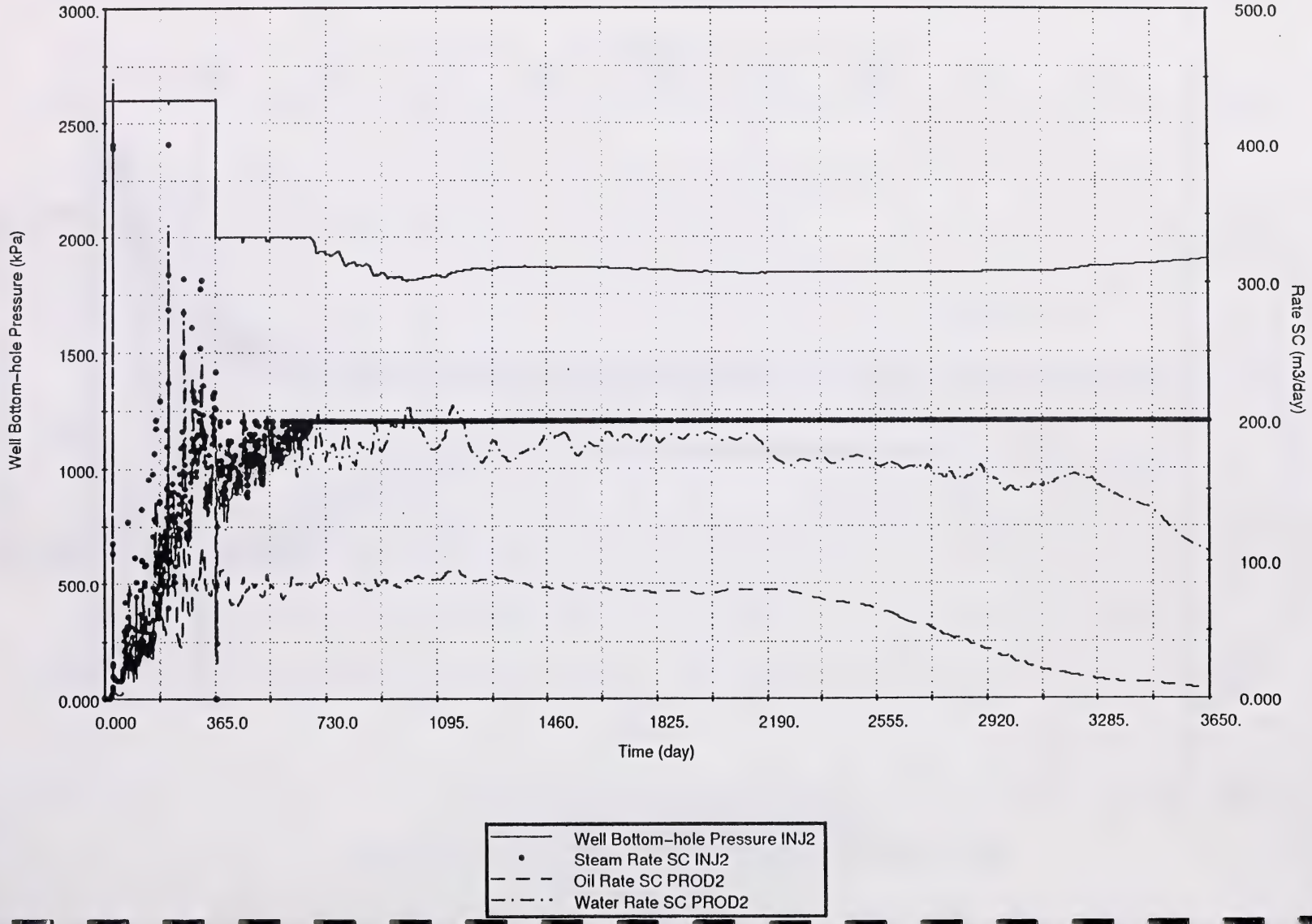

Athabasca McMurray - 10 m Depleted Gas Cap - OPT
Well Pair No. 1 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ1
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1

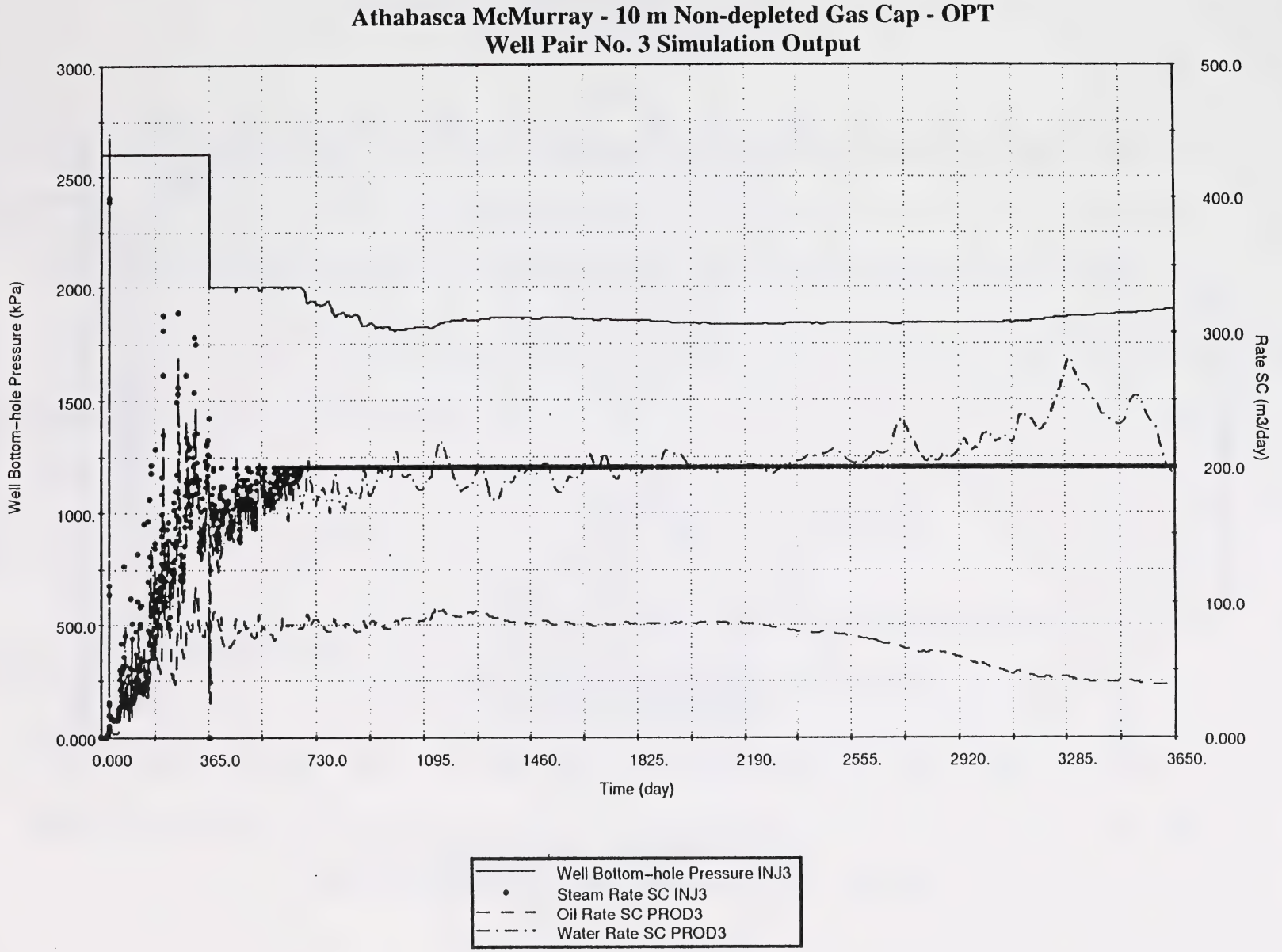

Athabasca McMurray - 10 m Depleted Gas Cap - OPT
Well Pair No. 2 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
600.0
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ2
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2

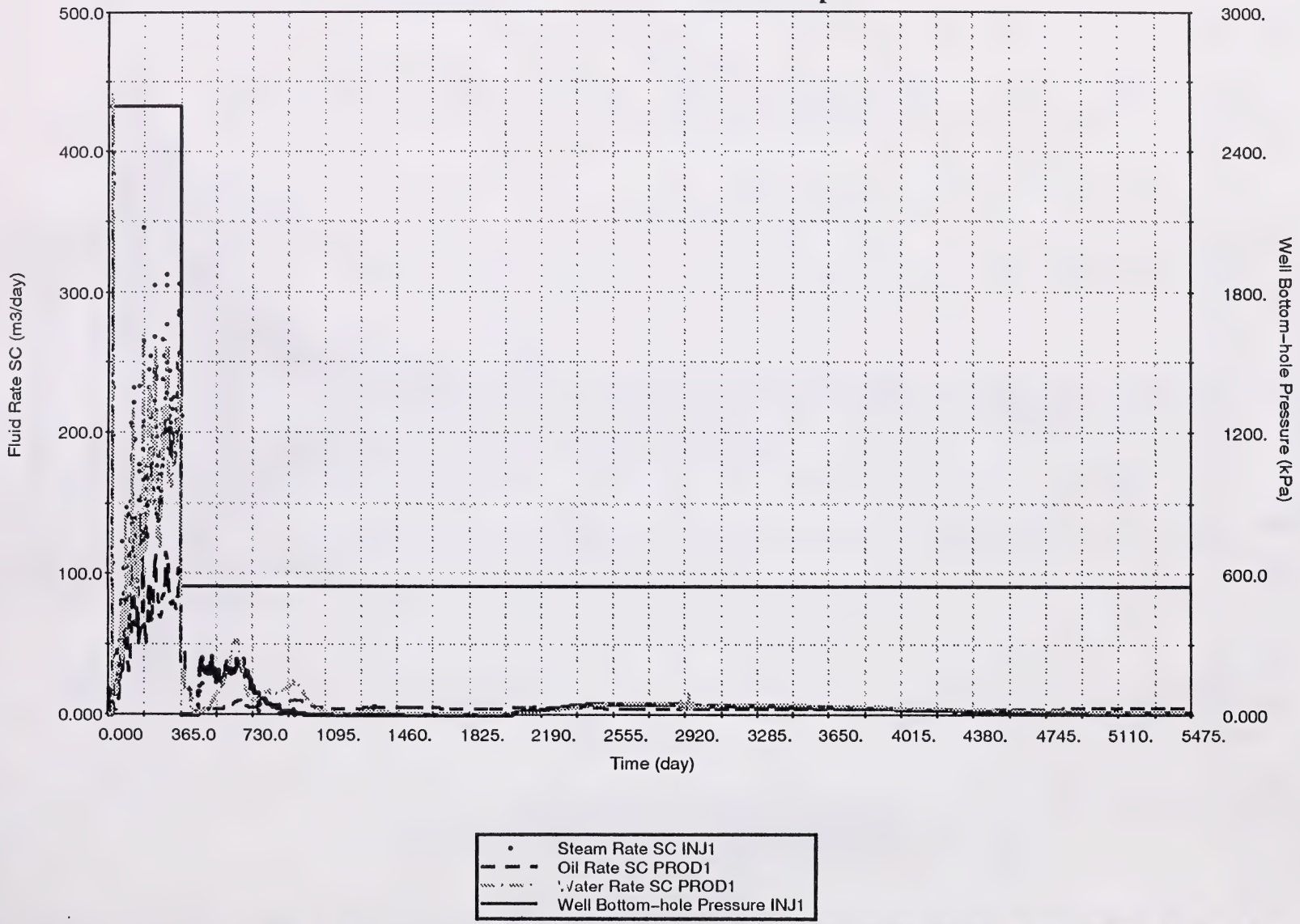

Athabasca McMurray - 10 m Depleted Gas Cap - OPT
Well Pair No. 3 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
600.0
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ3
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3

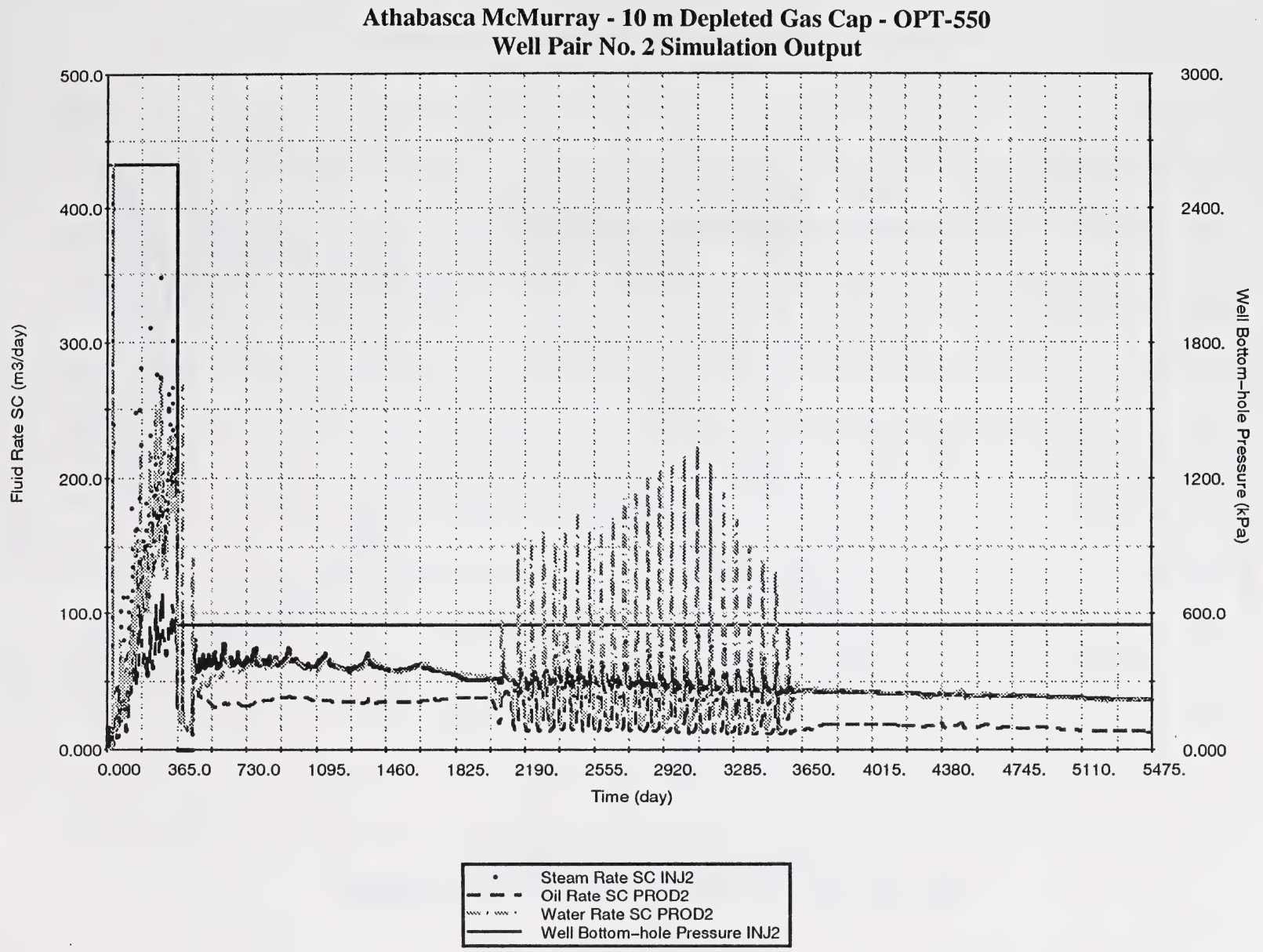

Athabasca McMurray - 10 m Non-depleted Gas Cap - OPT
Well Pair No. 1 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ1
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1

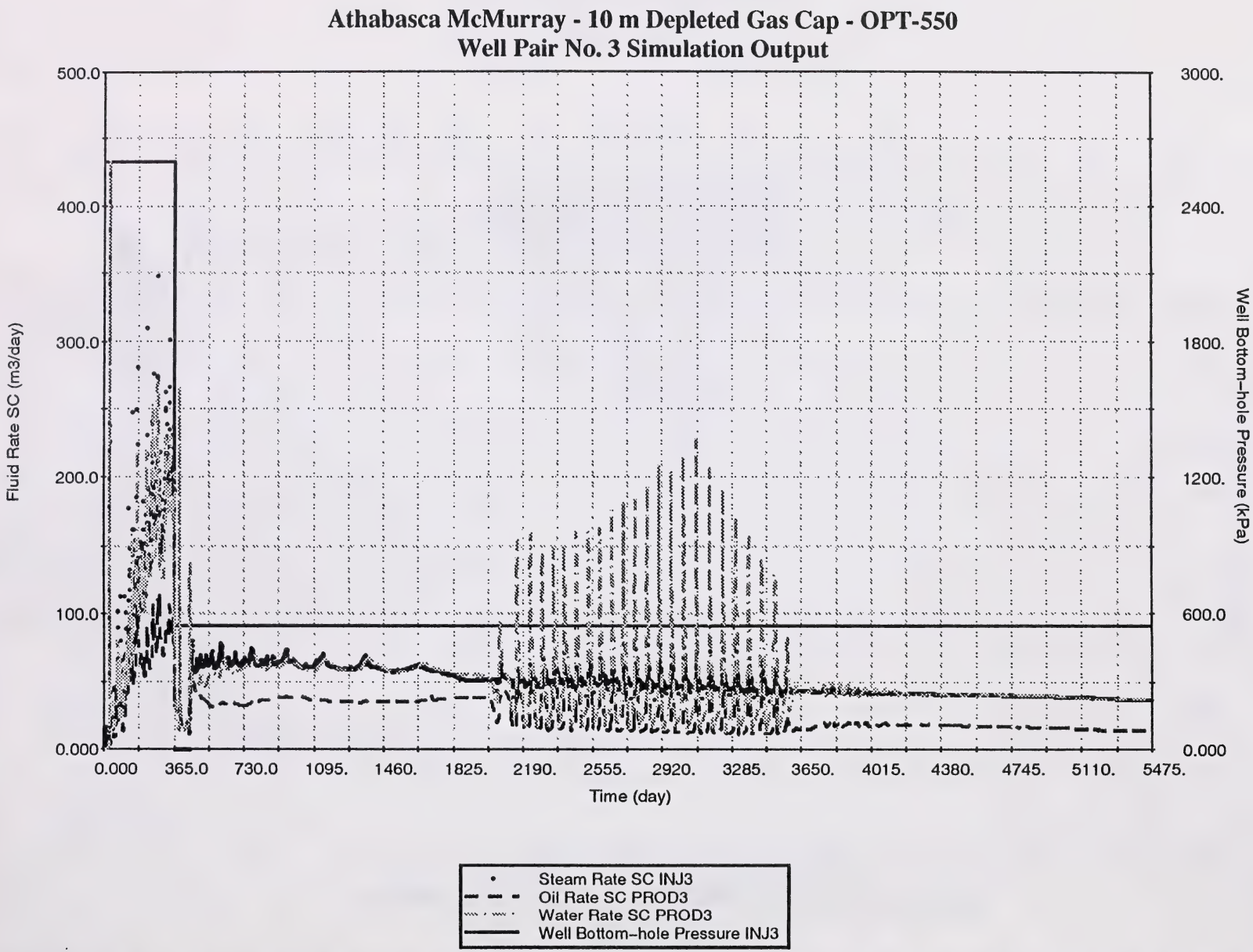
Athabasca McMurray - 10 m Non-depleted Gas Cap - OPT
Well Pair No. 2 Simulation Output

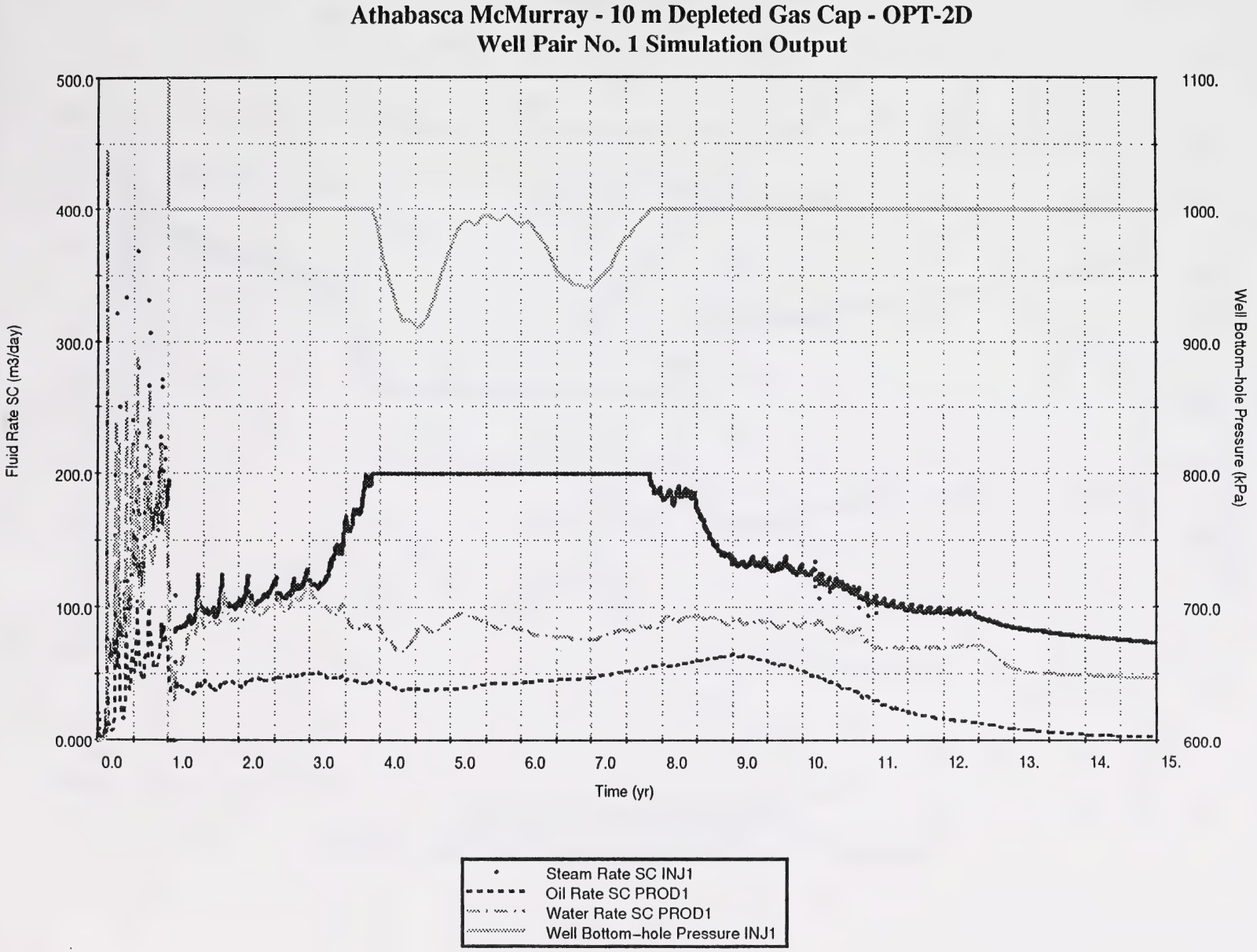


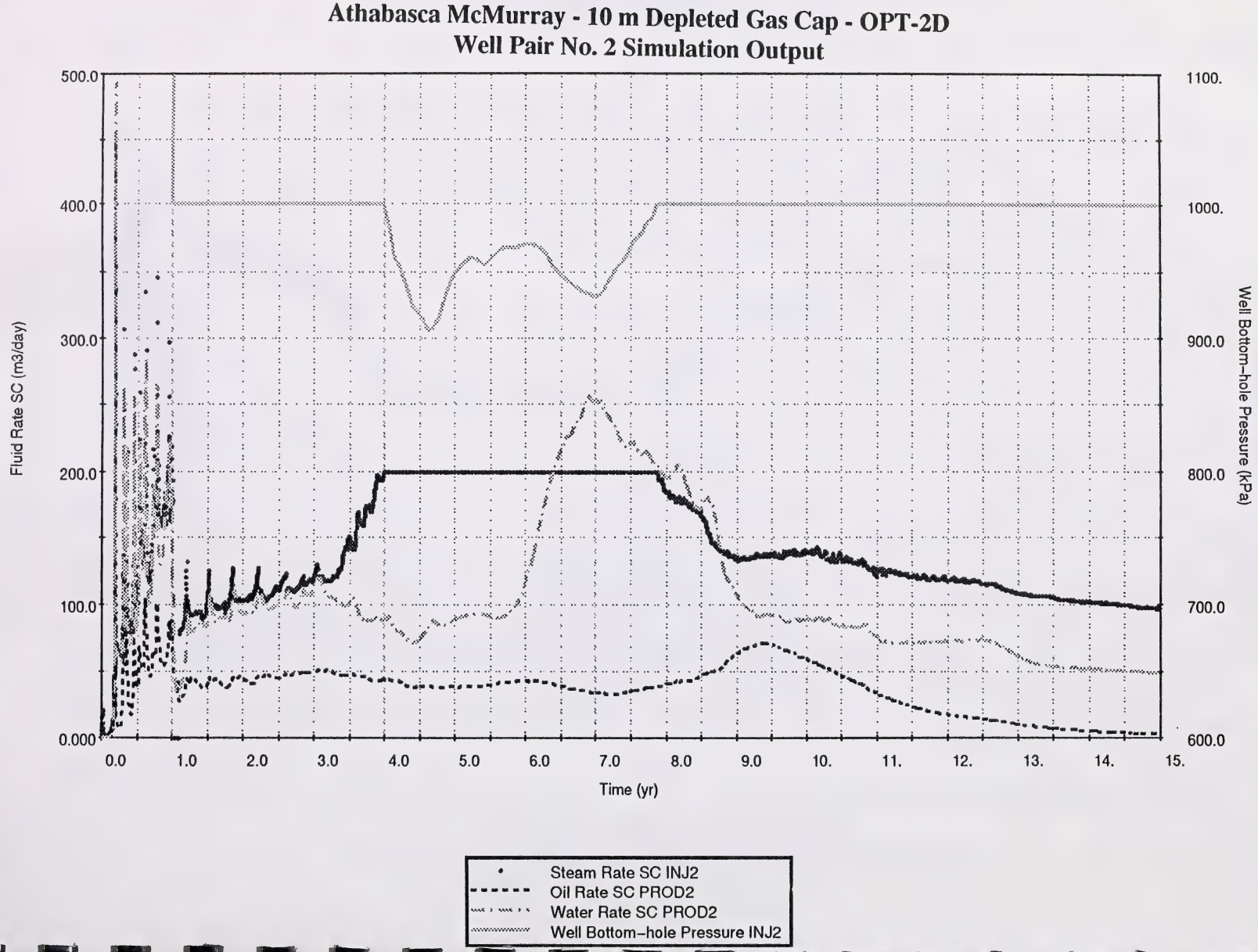

Athabasca McMurray - 10 m Non-depleted Gas Cap - OPT
Well Pair No. 3 Simulation Output
Well Bottom-hole Pressure (kPa)
Rate SC (m3/day)
Time (day)
3000.
2500.
2000.
1500.
1000.
500.0
0.000
500.0
400.0
300.0
200.0
100.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
Well Bottom-hole Pressure INJ3
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3

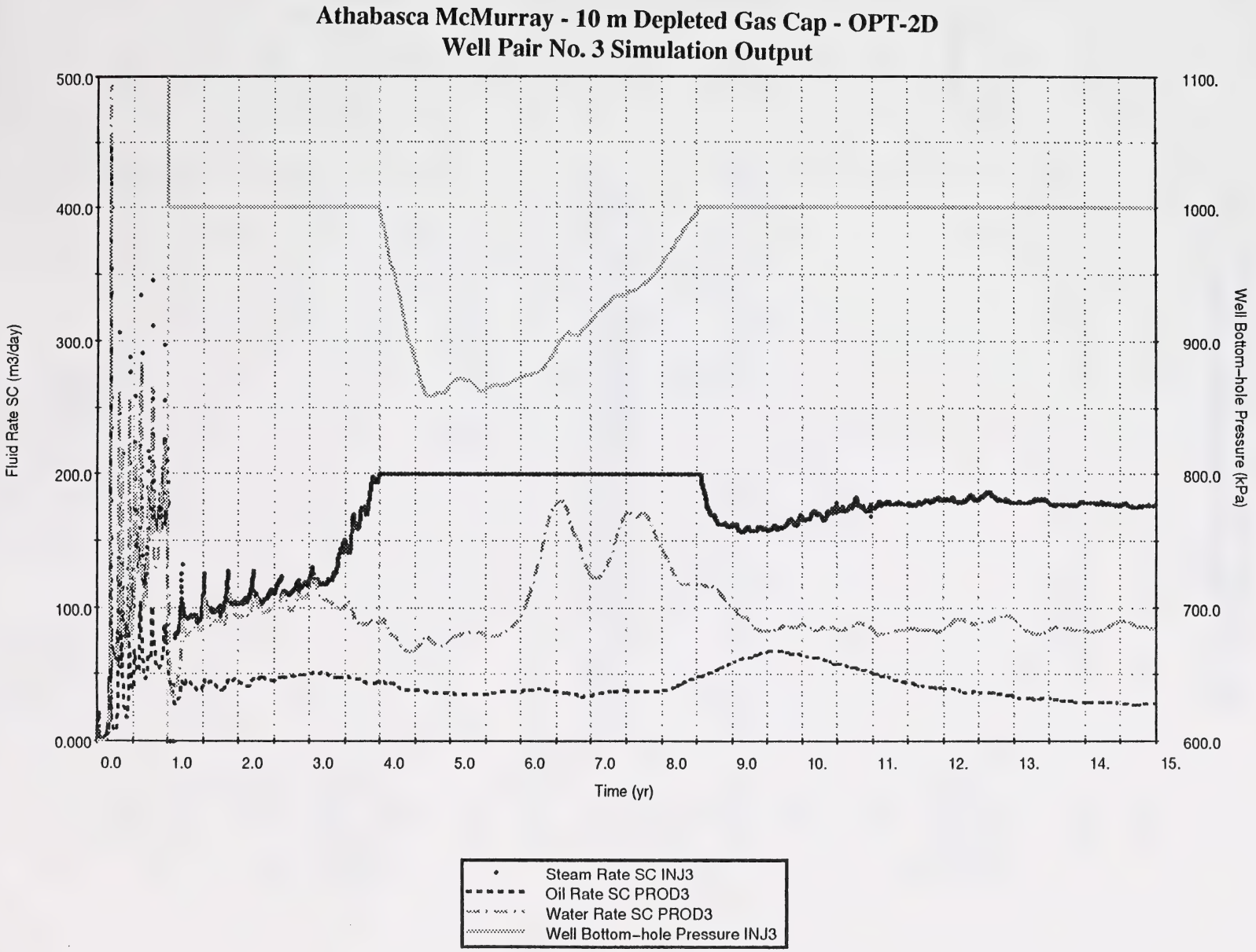

Athabasca McMurray - 10 m Depleted Gas Cap - OPT-550
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
Well Bottom-hole Pressure (kPa)
Time (day)
500.0
400.0
300.0
200.0
100.0
0.000
3000.
2400.
1800.
1200.
600.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1


Athabasca McMurray - 10 m Depleted Gas Cap - OPT-550
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
Well Bottom-hole Pressure (kPa)
Time (day)
500.0
400.0
300.0
200.0
100.0
0.000
3000.
2400.
1800.
1200.
600.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2

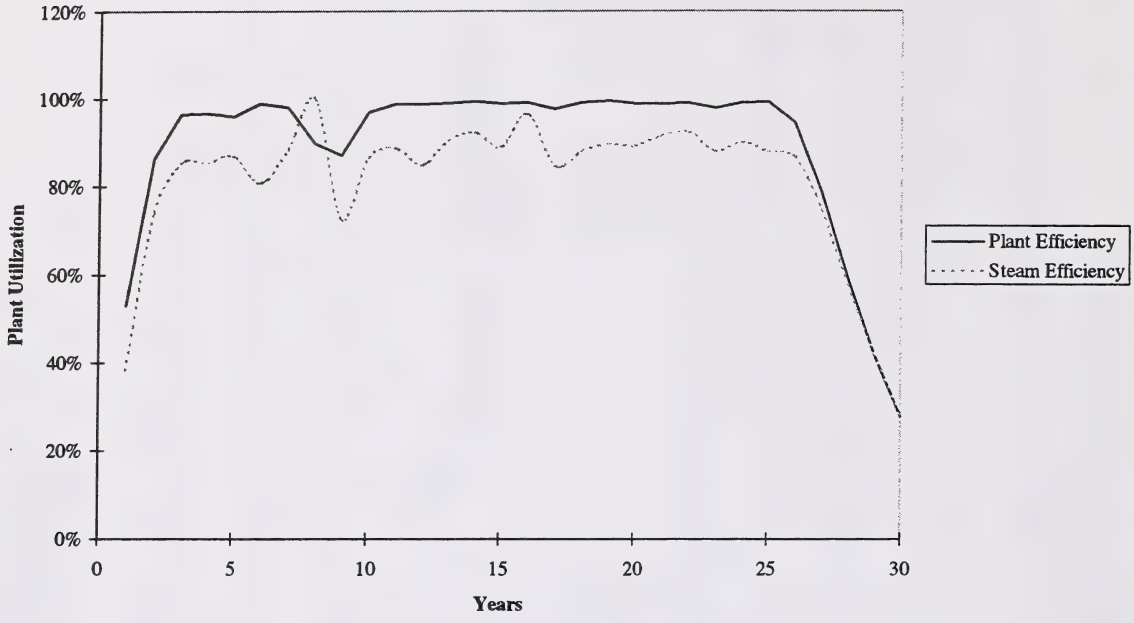

Athabasca McMurray - 10 m Depleted Gas Cap - OPT-550
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
3000.
2400.
1800.
1200.
600.0
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3


Athabasca McMurray - 10 m Depleted Gas Cap - OPT-2D
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
Well Bottom-hole Pressure (kPa)
Time (yr)
500.0
400.0
300.0
200.0
100.0
0.000
1100.
1000.
900.0
800.0
700.0
600.0
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
10.
11.
12.
13.
14.
15.
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1

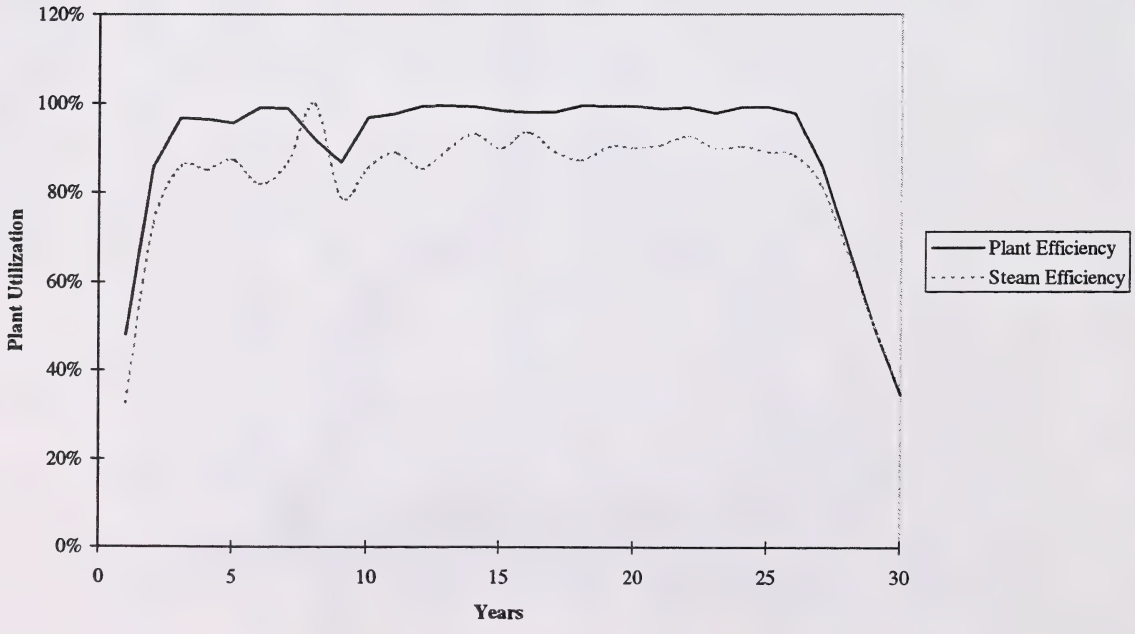

Athabasca McMurray - 10 m Depleted Gas Cap - OPT-2D
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
Well Bottom-hole Pressure (kPa)
Time (yr)
500.0
400.0
300.0
200.0
100.0
0.000
1100.
1000.
900.0
800.0
700.0
600.0
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
10.
11.
12.
13.
14.
15.
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2


Athabasca McMurray - 10 m Depleted Gas Cap - OPT-2D
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
Well Bottom-hole Pressure (kPa)
Time (yr)
500.0
400.0
300.0
200.0
100.0
0.000
1100.
1000.
900.0
800.0
700.0
600.0
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
10.
11.
12.
13.
14.
15.
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3

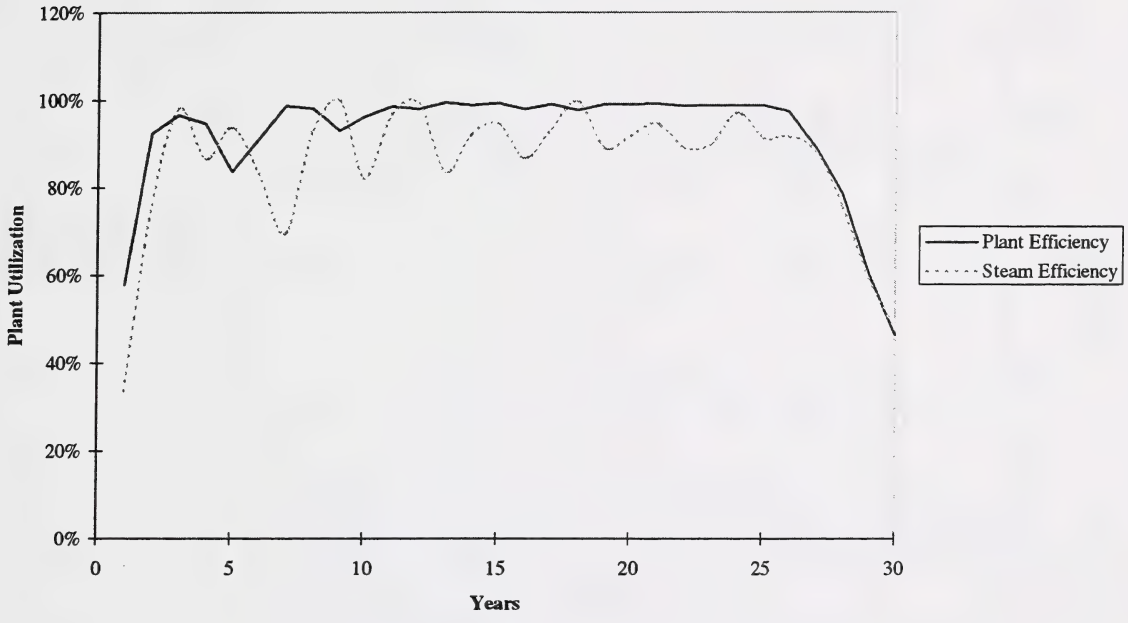
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 0 m Depleted Gas Cap



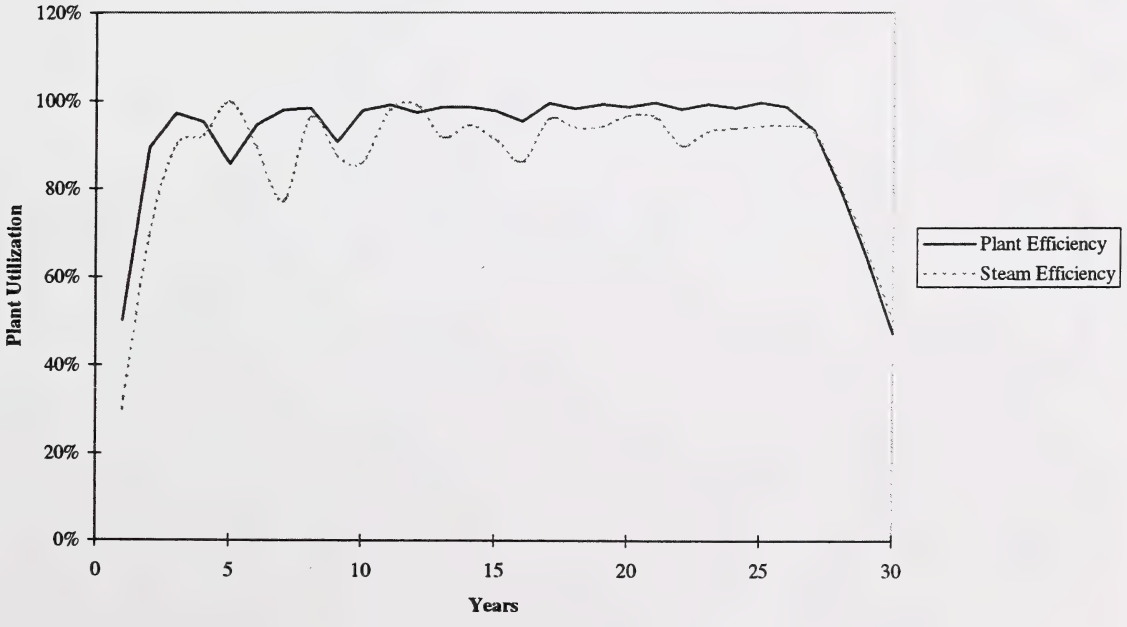
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 0 m Non-depleted Gas Cap



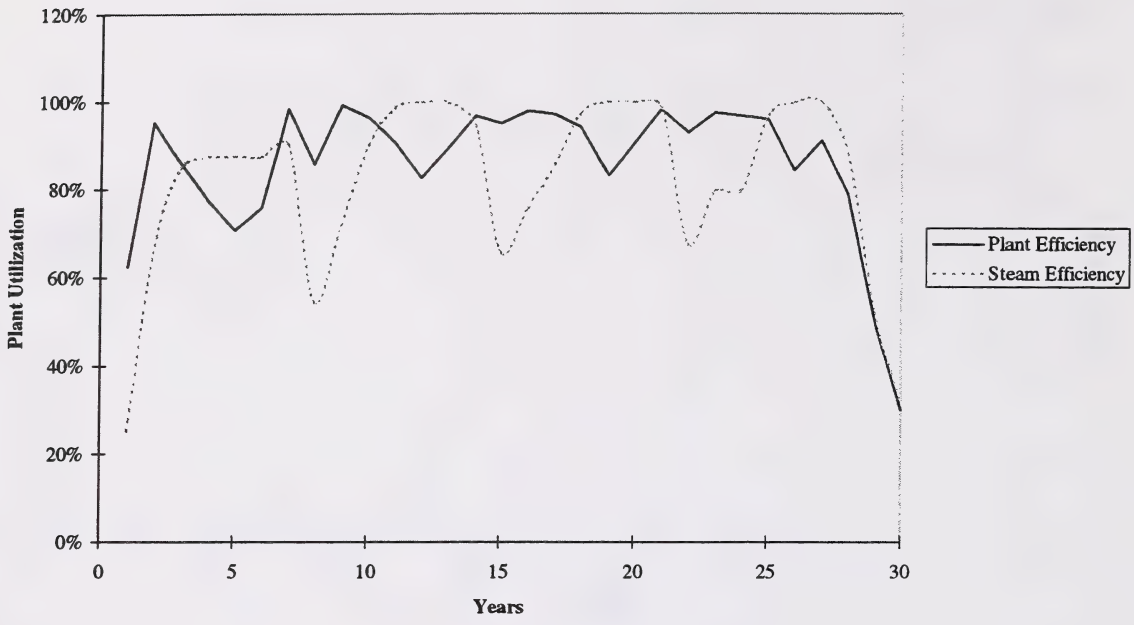
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 5 m Depleted Gas Cap



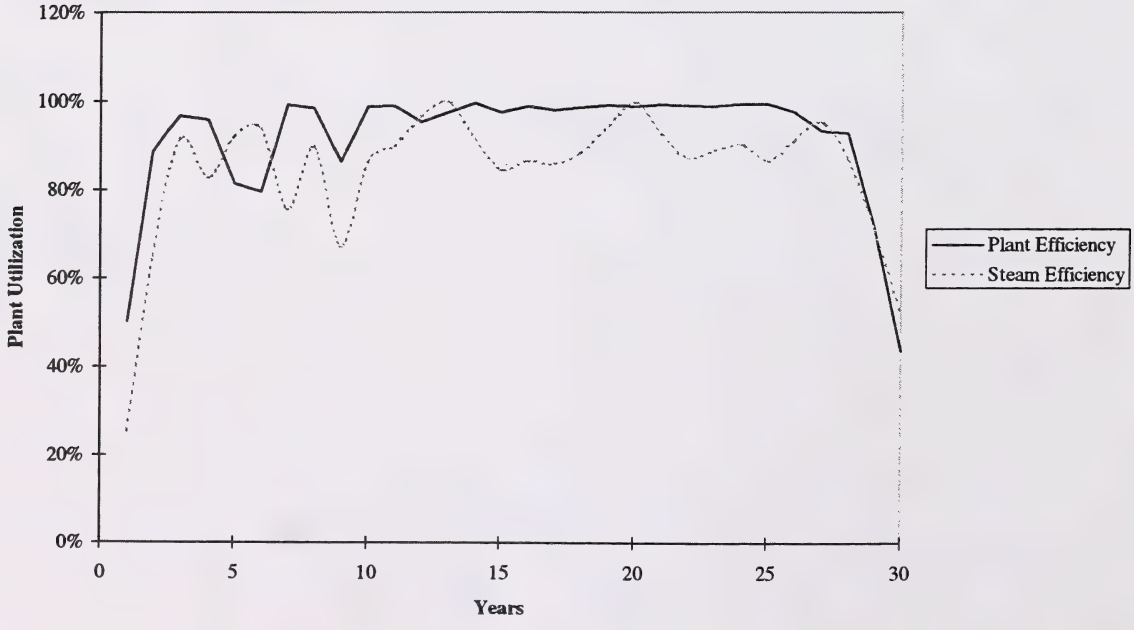
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 5 m Non-depleted Gas Cap



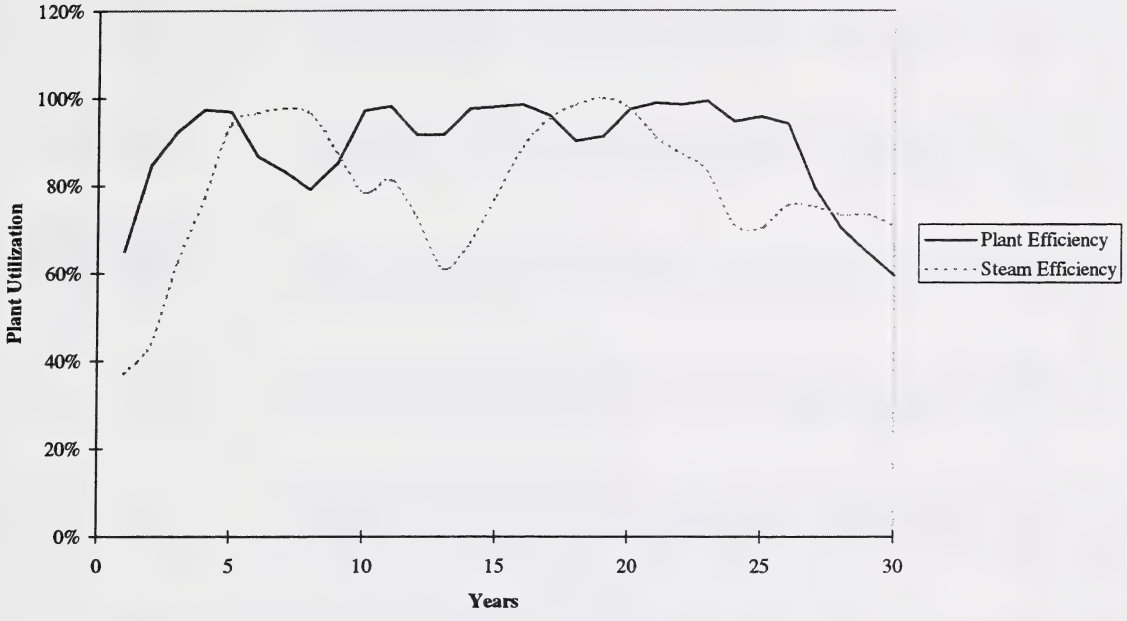
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 10 m Depleted Gas Cap



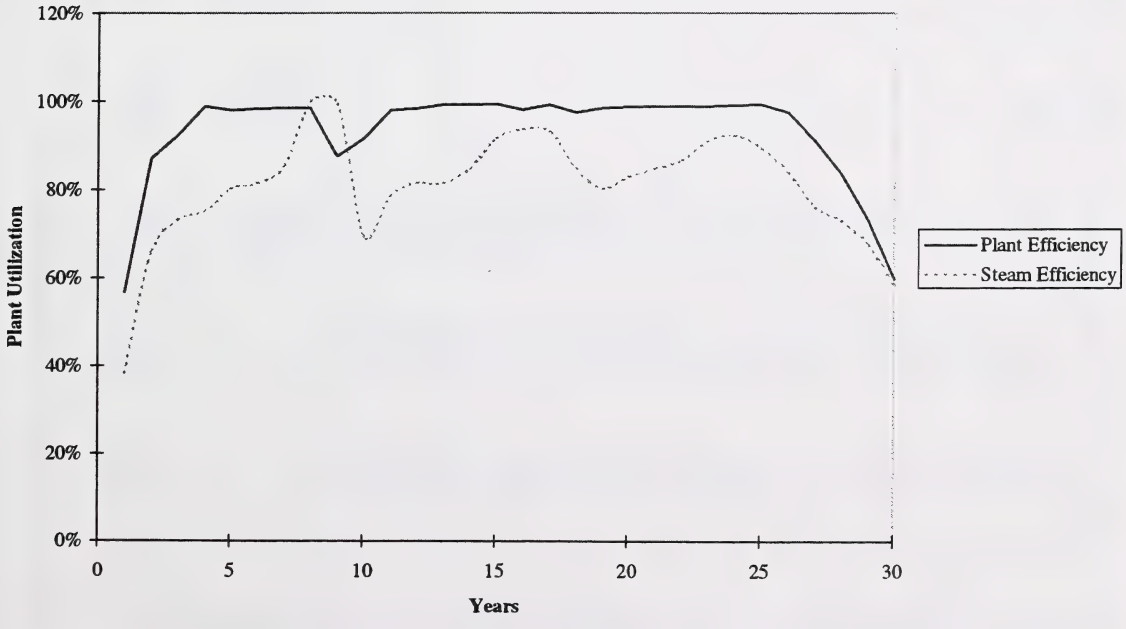
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 10 m Non-depleted Gas Cap



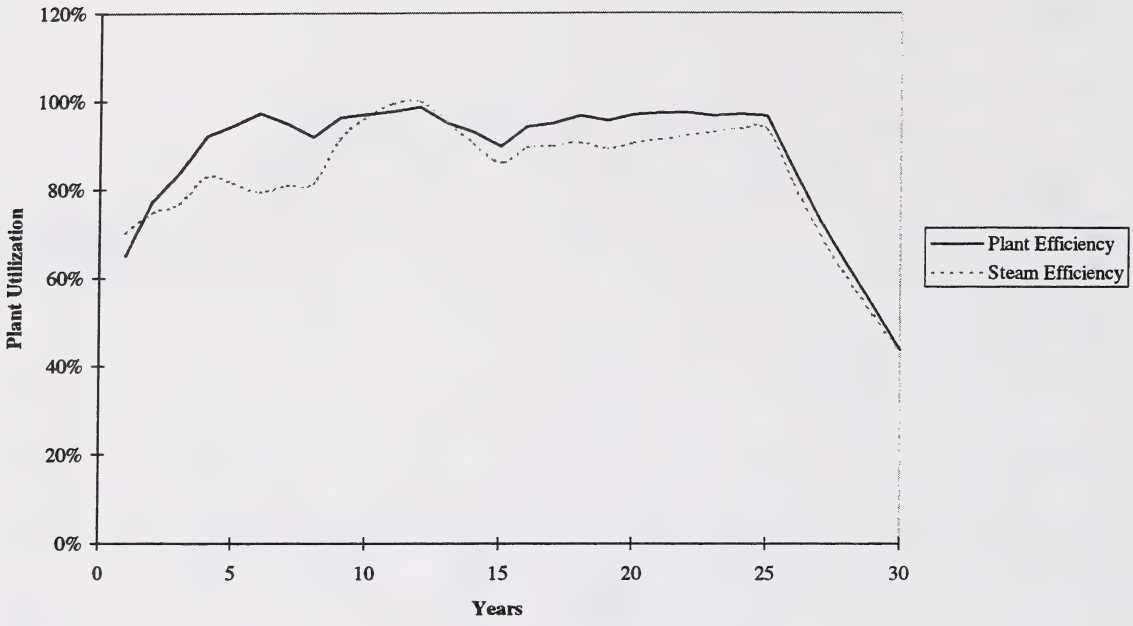
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 10 m Depleted Gas Cap - OPT (1000 kPa)



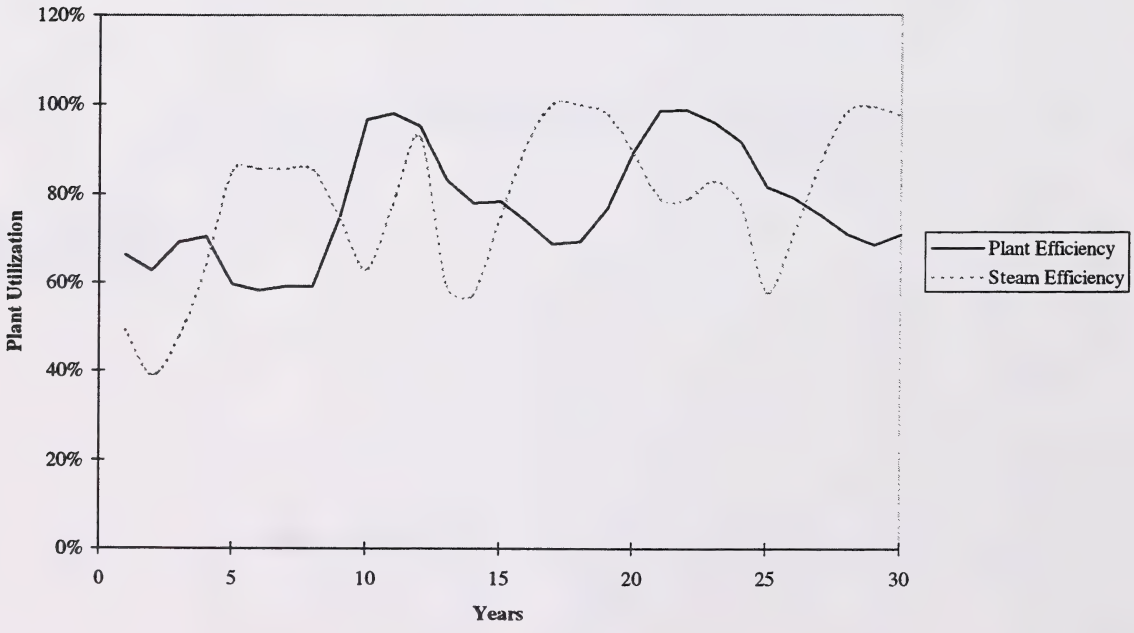
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 10 m Non-depleted Gas Cap - OPT (1800 kPa)



Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 10 m Depleted Gas Cap (Injection reduced to 550 kPa after 1 yr)



Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 10 m Depleted Gas Cap - OPT (2D)



Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 0 m Depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$89	$235	$324						
1997	15			$20,250	$120	$319	$20,689						
1998	15			$20,250	$29,511	$78,072	$127,833						
1999	14			$18,900	$30,271	$80,082	$129,252						
2000	9	2,523	5,734	$12,150	$8,049	$21,293	$41,492	$11,732	$3,160	$799	$843	$10,850	$27,385
2001	9	4,113	11,136	$12,150			$12,150	$22,783	$6,137	$1,180	$1,661	$10,850	$42,612
2002	9	4,600	12,809	$12,150			$12,150	$26,206	$7,059	$1,297	$1,952	$10,850	$47,364
2003	9	4,608	12,828	$12,150			$12,150	$26,246	$7,070	$1,299	$2,002	$10,850	$47,468
2004	9	4,575	13,064	$12,150			$12,150	$26,728	$7,200	$1,291	$2,120	$10,850	$48,190
2005	9	4,720	12,145	$12,150			$12,150	$24,848	$6,694	$1,326	$1,990	$10,850	$45,708
2006	9	4,677	13,289	$12,150			$12,150	$27,188	$7,324	$1,315	$2,140	$10,850	$48,818
2007	9	4,283	15,025	$12,150			$12,150	$30,739	$8,281	$1,221	$2,378	$10,850	$53,469
2008	9	4,154	10,905	$12,150			$12,150	$22,312	$6,011	$1,190	$1,662	$10,850	$42,025
2009	9	4,624	12,996	$12,150			$12,150	$26,589	$7,163	$1,303	$2,007	$10,850	$47,911
2010	9	4,712	13,337	$12,150			$12,150	$27,286	$7,350	$1,324	$2,110	$10,850	$48,921
2011	9	4,711	12,748	$12,150			$12,150	$26,082	$7,026	$1,324	$2,043	$10,850	$47,324
2012	9	4,724	13,607	$12,150			$12,150	$27,839	$7,500	$1,327	$2,195	$10,850	$49,710
2013	9	4,742	13,857	$12,150			$12,150	$28,350	$7,637	$1,331	$2,210	$10,850	$50,378
2014	9	4,716	13,360	$12,150			$12,150	$27,334	$7,363	$1,325	$2,094	$10,850	$48,966
2015	9	4,728	14,513	$12,150			$12,150	$29,693	$7,999	$1,328	$2,272	$10,850	$52,141
2016	9	4,659	12,711	$12,150			$12,150	$26,006	$7,006	$1,311	$1,987	$10,850	$47,160
2017	5	4,729	13,232	$6,750			$6,750	$27,072	$7,293	$1,328	$2,099	$10,850	$48,641
2018	0	4,752	13,475	$0			$0	$27,568	$7,427	$1,333	$2,159	$10,850	$49,337
2019	0	4,721	13,390	$0			$0	$27,395	$7,380	$1,326	$2,140	$10,850	$49,091
2020	0	4,721	13,749	$0			$0	$28,129	$7,578	$1,326	$2,178	$10,850	$50,060
2021	0	4,722	13,883	$0			$0	$28,404	$7,652	$1,326	$2,182	$10,850	$50,414
2022	0	4,671	13,227	$0			$0	$27,062	$7,290	$1,314	$2,072	$10,850	$48,589
2023	0	4,730	13,536	$0			$0	$27,694	$7,460	$1,328	$2,137	$10,850	$49,470
2024	0	4,734	13,211	$0			$0	$27,029	$7,281	$1,329	$2,099	$10,850	$48,588
2025	0	4,517	13,026	$0			$0	$26,650	$7,179	$1,277	$2,085	$10,850	$48,041
2026	0	3,760	11,237	$0			$0	$22,991	$6,194	$1,096	$1,812	$10,850	$42,943
2027	0	2,835	8,693	$0			$0	$17,785	$4,791	$874	$1,416	$10,850	$35,716
2028	0	2,000	6,342	$0			$0	$12,975	$3,495	$674	$1,042	$10,850	$29,036
2029	0	1,331	4,197	$0			$0	$8,587	$2,313	$514	$695	$20,950	$33,059
Totals	202	46,754,052	133,320,480	$272,700	$68,040	$180,000	$520,740	$747,301	$201,314	$36,537	$57,783	$335,600	$1,378,536

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 0 m Non-depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$88	$235	$322						
1997	15			$20,250	$119	$319	$20,688						
1998	15			$20,250	$29,152	$78,072	$127,474						
1999	14			$18,900	$29,903	$80,082	$128,884						
2000	9	2,294	4,836	$12,150	$7,951	$21,293	$41,394	$9,895	$2,666	$745	$729	$10,850	$24,884
2001	9	4,088	10,846	$12,150			$12,150	$22,190	$5,978	$1,174	$1,636	$10,850	$41,828
2002	9	4,610	12,737	$12,150			$12,150	$26,059	$7,020	$1,299	$1,935	$10,850	$47,163
2003	9	4,601	12,647	$12,150			$12,150	$25,875	$6,971	$1,297	$1,963	$10,850	$46,956
2004	9	4,557	12,985	$12,150			$12,150	$26,565	$7,156	$1,287	$2,111	$10,850	$47,970
2005	9	4,723	12,159	$12,150			$12,150	$24,877	$6,702	$1,326	$1,988	$10,850	$45,742
2006	9	4,718	12,891	$12,150			$12,150	$26,374	$7,105	$1,325	$2,102	$10,850	$47,756
2007	9	4,395	14,842	$12,150			$12,150	$30,366	$8,180	$1,248	$2,360	$10,850	$53,003
2008	9	4,142	11,716	$12,150			$12,150	$23,969	$6,457	$1,187	$1,813	$10,850	$44,276
2009	9	4,622	12,685	$12,150			$12,150	$25,953	$6,991	$1,302	$1,965	$10,850	$47,061
2010	9	4,660	13,220	$12,150			$12,150	$27,047	$7,286	$1,311	$2,083	$10,850	$48,579
2011	9	4,742	12,680	$12,150			$12,150	$25,942	$6,988	$1,331	$2,030	$10,850	$47,141
2012	9	4,750	13,337	$12,150			$12,150	$27,286	$7,351	$1,333	$2,156	$10,850	$48,976
2013	9	4,736	13,849	$12,150			$12,150	$28,333	$7,633	$1,330	$2,222	$10,850	$50,367
2014	9	4,695	13,342	$12,150			$12,150	$27,296	$7,353	$1,320	$2,117	$10,850	$48,936
2015	9	4,680	13,917	$12,150			$12,150	$28,474	$7,671	$1,316	$2,183	$10,850	$50,494
2016	9	4,683	13,255	$12,150			$12,150	$27,120	$7,306	$1,317	$2,081	$10,850	$48,673
2017	5	4,750	12,969	$6,750			$6,750	$26,533	$7,148	$1,333	$2,054	$10,850	$47,917
2018	0	4,744	13,411	$0			$0	$27,439	$7,392	$1,331	$2,146	$10,850	$49,158
2019	0	4,742	13,370	$0			$0	$27,354	$7,369	$1,331	$2,147	$10,850	$49,051
2020	0	4,712	13,474	$0			$0	$27,566	$7,426	$1,324	$2,150	$10,850	$49,316
2021	0	4,729	13,762	$0			$0	$28,157	$7,585	$1,328	$2,179	$10,850	$50,098
2022	0	4,668	13,367	$0			$0	$27,348	$7,367	$1,313	$2,106	$10,850	$48,985
2023	0	4,731	13,413	$0			$0	$27,443	$7,393	$1,328	$2,117	$10,850	$49,131
2024	0	4,732	13,239	$0			$0	$27,086	$7,297	$1,329	$2,103	$10,850	$48,663
2025	0	4,669	13,136	$0			$0	$26,876	$7,240	$1,314	$2,101	$10,850	$48,380
2026	0	4,108	12,077	$0			$0	$24,710	$6,656	$1,179	$1,943	$10,850	$45,338
2027	0	3,257	9,884	$0			$0	$20,222	$5,448	$975	$1,603	$10,850	$39,099
2028	0	2,386	7,452	$0			$0	$15,247	$4,107	$767	$1,220	$10,850	$32,191
2029	0	1,658	5,275	$0			$0	$10,793	$2,907	$592	$871	$20,950	$36,113
Totals	202	47,297,248	133,872,411	$272,700	$67,213	$180,000	$519,913	$750,395	$202,147	$36,893	$58,213	$335,600	$1,383,249

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 5 m Depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$110	$235	$345						
1997	16			$21,600	$150	$319	$22,068						
1998	16			$21,600	$36,668	$78,072	$136,340						
1999	16			$21,600	$37,612	$80,082	$139,294						
2000	9	2,756	6,261	$12,150	$10,001	$21,293	$43,444	$12,809	$3,451	$855	$920	$10,850	$28,885
2001	9	4,408	14,180	$12,150			$12,150	$29,010	$7,815	$1,251	$1,726	$10,850	$50,652
2002	9	4,610	18,319	$12,150			$12,150	$37,479	$10,096	$1,299	$1,824	$10,850	$61,549
2003	9	4,517	16,156	$12,150			$12,150	$33,054	$8,904	$1,277	$2,113	$10,850	$56,199
2004	9	3,984	17,533	$12,150			$12,150	$35,870	$9,663	$1,150	$2,465	$10,850	$59,998
2005	9	4,347	15,544	$12,150			$12,150	$31,802	$8,567	$1,236	$2,494	$10,850	$54,950
2006	9	4,711	12,988	$12,150			$12,150	$26,573	$7,159	$1,323	$1,908	$10,850	$47,813
2007	9	4,686	17,401	$12,150			$12,150	$35,602	$9,591	$1,318	$2,485	$10,850	$59,845
2008	9	4,439	18,668	$12,150			$12,150	$38,194	$10,289	$1,258	$2,261	$10,850	$62,853
2009	9	4,591	15,310	$12,150			$12,150	$31,324	$8,438	$1,295	$1,915	$10,850	$53,823
2010	9	4,705	18,070	$12,150			$12,150	$36,971	$9,960	$1,322	$2,323	$10,850	$61,425
2011	9	4,678	18,534	$12,150			$12,150	$37,920	$10,215	$1,316	$2,504	$10,850	$62,804
2012	9	4,745	15,576	$12,150			$12,150	$31,867	$8,585	$1,332	$2,238	$10,850	$54,871
2013	9	4,721	17,223	$12,150			$12,150	$35,238	$9,493	$1,326	$2,524	$10,850	$59,431
2014	9	4,740	17,682	$12,150			$12,150	$36,176	$9,745	$1,331	$2,458	$10,850	$60,560
2015	9	4,678	16,189	$12,150			$12,150	$33,123	$8,923	$1,316	$2,100	$10,850	$56,311
2016	9	4,728	17,467	$12,150			$12,150	$35,736	$9,627	$1,328	$2,297	$10,850	$59,837
2017	9	4,667	18,618	$12,150			$12,150	$38,091	$10,261	$1,313	$2,392	$10,850	$62,907
2018	2	4,728	16,623	$2,700			$2,700	$34,009	$9,162	$1,328	$2,261	$10,850	$57,609
2019	0	4,729	17,151	$0			$0	$35,090	$9,453	$1,328	$2,367	$10,850	$59,088
2020	0	4,733	17,687	$0			$0	$36,187	$9,748	$1,329	$2,522	$10,850	$60,636
2021	0	4,712	16,661	$0			$0	$34,086	$9,182	$1,324	$2,260	$10,850	$57,703
2022	0	4,718	16,760	$0			$0	$34,291	$9,237	$1,325	$2,319	$10,850	$58,022
2023	0	4,717	18,145	$0			$0	$37,123	$10,001	$1,325	$2,352	$10,850	$61,651
2024	0	4,720	17,055	$0			$0	$34,894	$9,400	$1,326	$2,284	$10,850	$58,754
2025	0	4,654	17,125	$0			$0	$35,037	$9,438	$1,310	$2,264	$10,850	$58,899
2026	0	4,254	16,494	$0			$0	$33,745	$9,091	$1,214	$2,283	$10,850	$57,183
2027	0	3,753	14,140	$0			$0	$28,929	$7,793	$1,094	$1,975	$10,850	$50,641
2028	0	2,869	11,072	$0			$0	$22,653	$6,103	$882	$1,640	$10,850	$42,128
2029	0	2,208	8,862	$0			$0	$18,132	$4,885	$724	$1,334	$21,450	$46,525
Totals	212	47,999,503	175,015,756	$286,200	$84,541	$180,000	$550,741	$981,016	$264,274	$37,354	$64,809	$336,100	$1,683,553

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 5 m Non-depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$100	$235	$334						
1997	16			$21,600	$135	$319	$22,054						
1998	16			$21,600	$33,105	$78,072	$132,777						
1999	14			$18,900	$33,958	$80,082	$132,939						
2000	9	2,398	5,051	$12,150	$9,029	$21,293	$42,472	$10,334	$2,784	$769	$761	$10,850	$25,499
2001	9	4,266	11,762	$12,150			$12,150	$24,063	$6,482	$1,217	$1,679	$10,850	$44,291
2002	9	4,639	15,204	$12,150			$12,150	$31,106	$8,379	$1,306	$1,858	$10,850	$53,499
2003	9	4,546	15,541	$12,150			$12,150	$31,796	$8,565	$1,284	$1,985	$10,850	$54,480
2004	9	4,089	16,854	$12,150			$12,150	$34,483	$9,289	$1,175	$2,313	$10,850	$58,110
2005	9	4,521	15,087	$12,150			$12,150	$30,867	$8,315	$1,278	$2,267	$10,850	$53,577
2006	9	4,676	13,027	$12,150			$12,150	$26,653	$7,180	$1,315	$1,996	$10,850	$47,994
2007	9	4,694	16,266	$12,150			$12,150	$33,279	$8,965	$1,319	$2,452	$10,850	$56,866
2008	9	4,328	14,774	$12,150			$12,150	$30,226	$8,143	$1,232	$2,092	$10,850	$52,542
2009	9	4,673	14,500	$12,150			$12,150	$29,666	$7,992	$1,315	$1,920	$10,850	$51,743
2010	9	4,727	16,526	$12,150			$12,150	$33,811	$9,108	$1,327	$2,229	$10,850	$57,325
2011	9	4,647	16,687	$12,150			$12,150	$34,140	$9,197	$1,308	$2,281	$10,850	$57,775
2012	9	4,708	15,464	$12,150			$12,150	$31,638	$8,523	$1,323	$2,213	$10,850	$54,547
2013	9	4,706	15,939	$12,150			$12,150	$32,611	$8,785	$1,322	$2,362	$10,850	$55,930
2014	9	4,664	15,380	$12,150			$12,150	$31,466	$8,477	$1,312	$2,292	$10,850	$54,397
2015	9	4,549	14,530	$12,150			$12,150	$29,728	$8,008	$1,285	$2,050	$10,850	$51,921
2016	9	4,748	16,186	$12,150			$12,150	$33,116	$8,921	$1,333	$2,277	$10,850	$56,497
2017	9	4,687	15,829	$12,150			$12,150	$32,386	$8,724	$1,318	$2,157	$10,850	$55,435
2018	4	4,735	15,868	$5,400			$5,400	$32,465	$8,746	$1,329	$2,181	$10,850	$55,571
2019	0	4,707	16,293	$0			$0	$33,335	$8,980	$1,323	$2,285	$10,850	$56,773
2020	0	4,753	16,240	$0			$0	$33,225	$8,950	$1,334	$2,368	$10,850	$56,728
2021	0	4,681	15,141	$0			$0	$30,978	$8,345	$1,316	$2,195	$10,850	$53,685
2022	0	4,737	15,687	$0			$0	$32,094	$8,646	$1,330	$2,255	$10,850	$55,175
2023	0	4,693	15,791	$0			$0	$32,307	$8,703	$1,319	$2,215	$10,850	$55,395
2024	0	4,756	15,894	$0			$0	$32,518	$8,760	$1,334	$2,220	$10,850	$55,682
2025	0	4,709	15,902	$0			$0	$32,535	$8,765	$1,323	$2,198	$10,850	$55,670
2026	0	4,459	15,651	$0			$0	$32,022	$8,626	$1,263	$2,200	$10,850	$54,962
2027	0	3,816	13,658	$0			$0	$27,942	$7,527	$1,109	$1,938	$10,850	$49,367
2028	0	3,065	11,136	$0			$0	$22,784	$6,138	$929	$1,642	$10,850	$42,343
2029	0	2,263	8,451	$0			$0	$17,291	$4,658	$737	$1,283	$21,450	$45,420
Totals	212	48,048,795	160,716,628	$286,200	$76,327	$180,000	$542,527	$900,865	$242,682	$37,387	$62,164	$336,100	$1,579,198

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 10 m Depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$159	$235	$394						
1997	18			$24,300	$216	$319	$24,835						
1998	18			$24,300	$53,002	$78,072	$155,374						
1999	16			$21,600	$54,367	$80,082	$156,048						
2000	9	2,982	6,780	$12,150	$14,456	$21,293	$47,899	$13,872	$3,737	$909	$997	$10,850	$30,365
2001	9	4,544	17,685	$12,150			$12,150	$36,181	$9,747	$1,284	$1,734	$10,850	$59,796
2002	9	4,114	22,903	$12,150			$12,150	$46,859	$12,623	$1,181	$1,434	$10,850	$72,947
2003	9	3,692	23,578	$12,150			$12,150	$48,240	$12,995	$1,079	$1,465	$10,850	$74,630
2004	9	3,373	23,639	$12,150			$12,150	$48,364	$13,029	$1,003	$1,984	$10,850	$75,229
2005	9	3,614	23,584	$12,150			$12,150	$48,250	$12,998	$1,061	$1,898	$10,850	$75,057
2006	9	4,694	24,336	$12,150			$12,150	$49,789	$13,413	$1,319	$1,833	$10,850	$77,205
2007	9	4,090	14,685	$12,150			$12,150	$30,045	$8,094	$1,175	$1,565	$10,850	$51,729
2008	9	4,732	19,364	$12,150			$12,150	$39,617	$10,672	$1,329	$1,774	$10,850	$64,243
2009	9	4,597	24,299	$12,150			$12,150	$49,714	$13,392	$1,296	$1,645	$10,850	$76,898
2010	9	4,329	26,618	$12,150			$12,150	$54,458	$14,670	$1,232	$1,781	$10,850	$82,992
2011	9	3,942	26,984	$12,150			$12,150	$55,208	$14,872	$1,139	$2,128	$10,850	$84,198
2012	9	4,270	26,959	$12,150			$12,150	$55,156	$14,858	$1,218	$2,107	$10,850	$84,190
2013	9	4,613	25,546	$12,150			$12,150	$52,266	$14,080	$1,300	$1,959	$10,850	$80,455
2014	9	4,531	17,733	$12,150			$12,150	$36,281	$9,774	$1,280	$1,776	$10,850	$59,961
2015	9	4,670	20,429	$12,150			$12,150	$41,797	$11,260	$1,314	$1,771	$10,850	$66,991
2016	9	4,635	23,096	$12,150			$12,150	$47,254	$12,730	$1,305	$1,653	$10,850	$73,792
2017	9	4,490	26,340	$12,150			$12,150	$53,891	$14,517	$1,271	$1,850	$10,850	$82,379
2018	9	3,965	26,961	$12,150			$12,150	$55,161	$14,860	$1,145	$2,046	$10,850	$84,061
2019	9	4,333	26,966	$12,150			$12,150	$55,170	$14,862	$1,233	$2,060	$10,850	$84,176
2020	9	4,687	26,618	$12,150			$12,150	$54,458	$14,670	$1,318	$2,112	$10,850	$83,408
2021	7	4,433	18,219	$9,450			$9,450	$37,276	$10,042	$1,257	$1,764	$10,850	$61,189
2022	0	4,653	21,452	$0			$0	$43,889	$11,823	$1,310	$1,747	$10,850	$69,619
2023	0	4,616	21,530	$0			$0	$44,049	$11,866	$1,301	$1,691	$10,850	$69,757
2024	0	4,581	26,180	$0			$0	$53,563	$14,429	$1,292	$1,887	$10,850	$82,022
2025	0	4,026	26,968	$0			$0	$55,175	$14,863	$1,159	$1,966	$10,850	$84,014
2026	0	4,354	26,968	$0			$0	$55,175	$14,863	$1,238	$2,024	$10,850	$84,151
2027	0	3,763	23,796	$0			$0	$48,685	$13,115	$1,096	$1,864	$10,850	$75,610
2028	0	2,380	14,085	$0			$0	$28,817	$7,763	$765	$1,055	$10,850	$49,250
2029	0	1,431	8,421	$0			$0	$17,229	$4,641	$538	$597	$23,250	$46,255
Totals	248	44,943,776	241,894,207	$334,800	$122,201	$180,000	$637,001	$1,355,890	$365,260	$35,349	$52,170	$337,900	$2,146,569

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 10 m Non-depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$117	$235	$352						
1997	16			$21,600	$159	$319	$22,078						
1998	16			$21,600	$39,045	$78,072	$138,717						
1999	14			$18,900	$40,051	$80,082	$139,032						
2000	9	2,399	5,060	$12,150	$10,649	$21,293	$44,093	$10,352	$2,789	$770	$762	$10,850	$25,522
2001	9	4,232	12,920	$12,150			$12,150	$26,434	$7,121	$1,209	$1,667	$10,850	$47,280
2002	9	4,618	18,194	$12,150			$12,150	$37,223	$10,028	$1,301	$1,818	$10,850	$61,221
2003	9	4,577	16,458	$12,150			$12,150	$33,671	$9,071	$1,291	$1,934	$10,850	$56,817
2004	9	3,889	18,337	$12,150			$12,150	$37,516	$10,106	$1,127	$2,686	$10,850	$62,284
2005	9	3,798	18,647	$12,150			$12,150	$38,150	$10,277	$1,105	$2,935	$10,850	$63,317
2006	9	4,733	15,026	$12,150			$12,150	$30,741	$8,281	$1,329	$2,247	$10,850	$53,448
2007	9	4,698	17,844	$12,150			$12,150	$36,508	$9,835	$1,321	$2,458	$10,850	$60,971
2008	9	4,125	13,338	$12,150			$12,150	$27,288	$7,351	$1,183	$1,681	$10,850	$48,353
2009	9	4,715	17,194	$12,150			$12,150	$35,177	$9,476	$1,325	$1,897	$10,850	$58,725
2010	9	4,723	17,914	$12,150			$12,150	$36,650	$9,873	$1,326	$2,169	$10,850	$60,868
2011	9	4,549	19,203	$12,150			$12,150	$39,288	$10,584	$1,285	$2,724	$10,850	$64,730
2012	9	4,648	19,879	$12,150			$12,150	$40,670	$10,956	$1,308	$2,888	$10,850	$66,673
2013	9	4,754	18,197	$12,150			$12,150	$37,230	$10,029	$1,334	$2,592	$10,850	$62,035
2014	9	4,650	16,826	$12,150			$12,150	$34,424	$9,273	$1,309	$2,389	$10,850	$58,246
2015	9	4,718	17,221	$12,150			$12,150	$35,234	$9,492	$1,325	$2,328	$10,850	$59,229
2016	9	4,675	17,094	$12,150			$12,150	$34,973	$9,421	$1,315	$2,024	$10,850	$58,584
2017	9	4,706	17,577	$12,150			$12,150	$35,962	$9,688	$1,322	$2,135	$10,850	$59,958
2018	9	4,729	18,789	$12,150			$12,150	$38,440	$10,355	$1,328	$2,599	$10,850	$63,572
2019	5	4,718	19,854	$6,750			$6,750	$40,620	$10,942	$1,325	$2,793	$10,850	$66,531
2020	0	4,737	18,408	$0			$0	$37,662	$10,146	$1,330	$2,521	$10,850	$62,509
2021	0	4,724	17,334	$0			$0	$35,465	$9,554	$1,327	$2,467	$10,850	$59,662
2022	0	4,715	17,680	$0			$0	$36,172	$9,744	$1,325	$2,476	$10,850	$60,568
2023	0	4,741	17,945	$0			$0	$36,715	$9,891	$1,331	$2,214	$10,850	$61,000
2024	0	4,741	17,220	$0			$0	$35,231	$9,491	$1,331	$2,127	$10,850	$59,029
2025	0	4,652	18,137	$0			$0	$37,107	$9,996	$1,309	$2,511	$10,850	$61,774
2026	0	4,449	18,936	$0			$0	$38,742	$10,437	$1,261	$2,603	$10,850	$63,892
2027	0	4,427	17,258	$0			$0	$35,308	$9,512	$1,256	$2,316	$10,850	$59,241
2028	0	3,383	14,096	$0			$0	$28,840	$7,769	$1,006	$1,986	$10,850	$50,451
2029	0	2,080	10,262	$0			$0	$20,996	$5,656	$693	$1,566	$21,950	$50,862
Totals	222	47,925,570	183,538,472	$299,700	$90,022	$180,000	$569,722	$1,028,788	$277,143	$37,306	$67,514	$336,600	$1,747,351

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 10 m Depleted Gas Cap - OPT (1000 kPa)

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$112	$235	$347						
1997	19			$25,650	$152	$319	$26,121						
1998	19			$25,650	$37,235	$78,072	$140,956						
1999	18			$24,300	$38,193	$80,082	$142,575						
2000	20	3,104	7,055	$27,000	$10,155	$21,293	$58,449	$14,435	$3,889	$939	$1,037	$10,850	$31,149
2001	9	4,044	8,299	$12,150			$12,150	$16,979	$4,574	$1,164	$1,228	$10,850	$34,795
2002	9	4,411	11,847	$12,150			$12,150	$24,237	$6,529	$1,252	$1,389	$10,850	$44,257
2003	9	4,643	14,623	$12,150			$12,150	$29,918	$8,059	$1,307	$1,441	$10,850	$51,575
2004	9	4,624	17,838	$12,150			$12,150	$36,496	$9,832	$1,303	$1,410	$10,850	$59,890
2005	9	4,140	18,315	$12,150			$12,150	$37,471	$10,094	$1,187	$1,404	$10,850	$61,005
2006	9	3,968	18,528	$12,150			$12,150	$37,907	$10,212	$1,145	$1,779	$10,850	$61,894
2007	9	3,776	18,286	$12,150			$12,150	$37,412	$10,078	$1,100	$2,252	$10,850	$61,692
2008	9	4,055	16,584	$12,150			$12,150	$33,929	$9,140	$1,167	$2,006	$10,850	$57,092
2009	9	4,635	14,854	$12,150			$12,150	$30,391	$8,187	$1,305	$1,552	$10,850	$52,285
2010	9	4,680	15,428	$12,150			$12,150	$31,565	$8,503	$1,316	$1,583	$10,850	$53,818
2011	9	4,367	13,801	$12,150			$12,150	$28,236	$7,606	$1,241	$1,567	$10,850	$49,500
2012	9	4,365	11,581	$12,150			$12,150	$23,694	$6,383	$1,241	$1,431	$10,850	$43,598
2013	9	4,648	12,691	$12,150			$12,150	$25,966	$6,995	$1,308	$1,459	$10,850	$46,578
2014	9	4,674	14,708	$12,150			$12,150	$30,092	$8,107	$1,315	$1,478	$10,850	$51,842
2015	9	4,699	16,815	$12,150			$12,150	$34,402	$9,268	$1,321	$1,490	$10,850	$57,331
2016	9	4,581	18,087	$12,150			$12,150	$37,004	$9,968	$1,292	$1,591	$10,850	$60,706
2017	9	4,299	18,668	$12,150			$12,150	$38,194	$10,289	$1,225	$1,806	$10,850	$62,364
2018	9	4,348	18,957	$12,150			$12,150	$38,784	$10,448	$1,237	$2,062	$10,850	$63,381
2019	9	4,645	18,535	$12,150			$12,150	$37,921	$10,215	$1,308	$2,084	$10,850	$62,378
2020	9	4,717	17,276	$12,150			$12,150	$35,346	$9,522	$1,325	$1,836	$10,850	$58,879
2021	2	4,699	16,534	$2,700			$2,700	$33,827	$9,113	$1,321	$1,741	$10,850	$56,851
2022	0	4,741	15,787	$0			$0	$32,300	$8,701	$1,331	$1,754	$10,850	$54,935
2023	0	4,514	13,509	$0			$0	$27,639	$7,445	$1,276	$1,562	$10,850	$48,772
2024	0	4,571	13,350	$0			$0	$27,312	$7,358	$1,290	$1,480	$10,850	$48,290
2025	0	4,492	14,315	$0			$0	$29,288	$7,890	$1,271	$1,481	$10,850	$50,780
2026	0	3,786	14,248	$0			$0	$29,151	$7,853	$1,102	$1,282	$10,850	$50,237
2027	0	3,352	13,893	$0			$0	$28,424	$7,657	$998	$1,164	$10,850	$49,093
2028	0	3,083	13,910	$0			$0	$28,459	$7,667	$934	$1,285	$10,850	$49,194
2029	0	2,843	13,409	$0			$0	$27,434	$7,390	$876	$1,435	$23,750	$60,886
Totals	258	46,538,512	164,881,602	$348,300	$85,848	$180,000	$614,148	$924,211	$248,971	$36,395	$47,070	$338,400	$1,595,047

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 10 m Non-depleted Gas Cap - OPT (1800 kPa)

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$88	$235	$323						
1997	18			$24,300	$120	$319	$24,739						
1998	18			$24,300	$29,375	$78,072	$131,746						
1999	16			$21,600	$30,131	$80,082	$131,813						
2000	9	2,711	5,720	$12,150	$8,012	$21,293	$41,455	$11,702	$3,152	$845	$862	$10,850	$27,411
2001	9	4,158	9,869	$12,150			$12,150	$20,191	$5,439	$1,191	$1,491	$10,850	$39,163
2002	9	4,399	10,947	$12,150			$12,150	$22,398	$6,034	$1,249	$1,675	$10,850	$42,205
2003	9	4,717	11,224	$12,150			$12,150	$22,963	$6,186	$1,325	$1,706	$10,850	$43,030
2004	9	4,676	11,995	$12,150			$12,150	$24,541	$6,611	$1,315	$1,861	$10,850	$45,179
2005	9	4,691	12,186	$12,150			$12,150	$24,931	$6,716	$1,319	$1,918	$10,850	$45,733
2006	9	4,697	12,793	$12,150			$12,150	$26,173	$7,051	$1,320	$1,934	$10,850	$47,328
2007	9	4,698	14,955	$12,150			$12,150	$30,597	$8,243	$1,320	$2,247	$10,850	$53,257
2008	9	4,179	14,881	$12,150			$12,150	$30,445	$8,202	$1,196	$2,233	$10,850	$52,926
2009	9	4,374	10,407	$12,150			$12,150	$21,293	$5,736	$1,243	$1,579	$10,850	$40,701
2010	9	4,676	11,750	$12,150			$12,150	$24,040	$6,476	$1,315	$1,788	$10,850	$44,469
2011	9	4,694	12,201	$12,150			$12,150	$24,962	$6,724	$1,320	$1,885	$10,850	$45,740
2012	9	4,736	12,184	$12,150			$12,150	$24,928	$6,715	$1,330	$1,871	$10,850	$45,694
2013	9	4,730	12,694	$12,150			$12,150	$25,971	$6,996	$1,328	$1,950	$10,850	$47,096
2014	9	4,743	13,706	$12,150			$12,150	$28,042	$7,554	$1,331	$2,088	$10,850	$49,866
2015	9	4,687	14,018	$12,150			$12,150	$28,679	$7,726	$1,318	$2,112	$10,850	$50,685
2016	9	4,739	13,946	$12,150			$12,150	$28,532	$7,686	$1,330	$2,105	$10,850	$50,504
2017	9	4,656	12,708	$12,150			$12,150	$25,999	$7,004	$1,310	$1,933	$10,850	$47,096
2018	6	4,702	12,014	$8,100			$8,100	$24,581	$6,622	$1,321	$1,838	$10,850	$45,212
2019	0	4,712	12,406	$0			$0	$25,382	$6,838	$1,324	$1,899	$10,850	$46,293
2020	0	4,719	12,696	$0			$0	$25,974	$6,997	$1,325	$1,951	$10,850	$47,098
2021	0	4,721	12,957	$0			$0	$26,509	$7,141	$1,326	$1,982	$10,850	$47,808
2022	0	4,714	13,593	$0			$0	$27,811	$7,492	$1,324	$2,066	$10,850	$49,543
2023	0	4,728	13,817	$0			$0	$28,268	$7,615	$1,328	$2,087	$10,850	$50,148
2024	0	4,731	13,388	$0			$0	$27,391	$7,379	$1,328	$2,032	$10,850	$48,980
2025	0	4,649	12,566	$0			$0	$25,709	$6,926	$1,309	$1,914	$10,850	$46,708
2026	0	4,345	11,396	$0			$0	$23,316	$6,281	$1,236	$1,747	$10,850	$43,430
2027	0	3,995	10,958	$0			$0	$22,419	$6,039	$1,152	$1,680	$10,850	$42,140
2028	0	3,491	10,112	$0			$0	$20,689	$5,573	$1,031	$1,552	$10,850	$39,696
2029	0	2,855	8,742	$0			$0	$17,885	$4,818	$879	$1,334	$21,850	$46,766
Totals	220	48,663,567	132,432,142	$297,000	$67,726	$180,000	$544,726	$742,322	$199,973	$37,790	$55,320	$336,500	$1,371,904

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 10 m Depleted Gas Cap (Injection reduced to 550 kPa after 1 yr)

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$59	$235	$294						
1997	19			$25,650	$80	$319	$26,049						
1998	19			$25,650	$19,708	$78,072	$123,430						
1999	18			$24,300	$20,216	$80,082	$124,597						
2000	36	3,104	7,055	$48,600	$5,375	$21,293	$75,269	$14,435	$3,889	$939	$1,037	$10,850	$31,149
2001	26	3,687	7,505	$35,100			$35,100	$15,355	$4,137	$1,078	$1,141	$10,850	$32,561
2002	18	3,997	7,715	$24,300			$24,300	$15,784	$4,252	$1,153	$1,203	$10,850	$33,242
2003	12	4,399	8,331	$16,200			$16,200	$17,046	$4,592	$1,249	$1,320	$10,850	$35,056
2004	9	4,507	8,176	$12,150			$12,150	$16,728	$4,506	$1,275	$1,310	$10,850	$34,670
2005	9	4,647	7,969	$12,150			$12,150	$16,303	$4,392	$1,308	$1,294	$10,850	$34,148
2006	9	4,533	8,114	$12,150			$12,150	$16,601	$4,472	$1,281	$1,294	$10,850	$34,498
2007	9	4,385	8,174	$12,150			$12,150	$16,724	$4,505	$1,245	$1,304	$10,850	$34,629
2008	12	4,595	9,179	$16,200			$16,200	$18,780	$5,059	$1,296	$1,436	$10,850	$37,421
2009	14	4,627	9,687	$18,900			$18,900	$19,819	$5,339	$1,303	$1,522	$10,850	$38,833
2010	10	4,664	9,972	$13,500			$13,500	$20,403	$5,496	$1,312	$1,583	$10,850	$39,645
2011	20	4,708	10,034	$27,000			$27,000	$20,528	$5,530	$1,323	$1,602	$10,850	$39,834
2012	16	4,538	9,559	$21,600			$21,600	$19,557	$5,268	$1,282	$1,528	$10,850	$38,485
2013	18	4,436	9,075	$24,300			$24,300	$18,567	$5,002	$1,258	$1,449	$10,850	$37,125
2014	18	4,281	8,631	$24,300			$24,300	$17,658	$4,757	$1,221	$1,360	$10,850	$35,845
2015	16	4,497	8,980	$21,600			$21,600	$18,373	$4,949	$1,272	$1,411	$10,850	$36,855
2016	14	4,530	9,012	$18,900			$18,900	$18,439	$4,967	$1,280	$1,417	$10,850	$36,953
2017	12	4,614	9,110	$16,200			$16,200	$18,638	$5,021	$1,300	$1,439	$10,850	$37,249
2018	10	4,561	8,948	$13,500			$13,500	$18,307	$4,932	$1,288	$1,419	$10,850	$36,795
2019	10	4,624	9,088	$13,500			$13,500	$18,593	$5,009	$1,303	$1,442	$10,850	$37,196
2020	12	4,639	9,163	$16,200			$16,200	$18,746	$5,050	$1,306	$1,455	$10,850	$37,407
2021	14	4,648	9,260	$18,900			$18,900	$18,945	$5,104	$1,309	$1,464	$10,850	$37,672
2022	16	4,617	9,340	$21,600			$21,600	$19,110	$5,148	$1,301	$1,476	$10,850	$37,884
2023	12	4,634	9,415	$16,200			$16,200	$19,262	$5,189	$1,305	$1,489	$10,850	$38,094
2024	0	4,615	9,380	$0			$0	$19,191	$5,170	$1,301	$1,491	$10,850	$38,002
2025	0	4,041	8,142	$0			$0	$16,657	$4,487	$1,163	$1,305	$10,850	$34,462
2026	0	3,488	7,000	$0			$0	$14,322	$3,858	$1,031	$1,131	$10,850	$31,192
2027	0	3,017	6,038	$0			$0	$12,353	$3,328	$918	$974	$10,850	$28,422
2028	0	2,548	5,155	$0			$0	$10,547	$2,841	$805	$832	$10,850	$25,875
2029	0	2,086	4,327	$0			$0	$8,853	$2,385	$695	$693	$31,250	$43,876
Totals	408	46,087,079	91,810,177	$550,800	$45,439	$180,000	$776,239	$514,624	$138,633	$36,099	$39,822	$345,900	$1,075,078

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 10 m Depleted Gas Cap - OPT (2D)

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$105	$235	$339						
1997	24			$32,400	$142	$319	$32,861						
1998	24			$32,400	$34,767	$78,072	$145,238						
1999	24			$32,400	$35,662	$80,082	$148,144						
2000	9	3,165	8,730	$12,150	$9,482	$21,293	$42,926	$17,860	$4,811	$953	$1,315	$10,850	$35,790
2001	9	2,991	6,903	$12,150			$12,150	$14,123	$3,805	$912	$1,045	$10,850	$30,735
2002	9	3,299	8,415	$12,150			$12,150	$17,216	$4,638	$985	$1,245	$10,850	$34,935
2003	9	3,360	11,300	$12,150			$12,150	$23,119	$6,228	$1,000	$1,214	$10,850	$42,411
2004	9	2,842	15,077	$12,150			$12,150	$30,846	$8,310	$876	$979	$10,850	$51,860
2005	9	2,782	15,158	$12,150			$12,150	$31,012	$8,354	$862	$1,082	$10,850	$52,159
2006	9	2,822	15,158	$12,150			$12,150	$31,012	$8,354	$871	$1,885	$10,850	$52,972
2007	9	2,822	15,093	$12,150			$12,150	$30,880	$8,319	$871	$2,054	$10,850	$52,974
2008	9	3,573	13,201	$12,150			$12,150	$27,009	$7,276	$1,051	$1,664	$10,850	$47,850
2009	9	4,608	11,150	$12,150			$12,150	$22,812	$6,145	$1,299	$1,137	$10,850	$42,243
2010	9	4,673	13,724	$12,150			$12,150	$28,079	$7,564	$1,315	$1,446	$10,850	$49,254
2011	9	4,539	16,372	$12,150			$12,150	$33,496	$9,023	$1,282	$1,791	$10,850	$56,443
2012	9	3,963	10,478	$12,150			$12,150	$21,438	$5,775	$1,144	$1,543	$10,850	$40,750
2013	9	3,715	10,133	$12,150			$12,150	$20,732	$5,585	$1,085	$1,347	$10,850	$39,599
2014	9	3,731	13,231	$12,150			$12,150	$27,070	$7,292	$1,089	$1,357	$10,850	$47,658
2015	9	3,516	16,140	$12,150			$12,150	$33,022	$8,896	$1,037	$1,295	$10,850	$55,100
2016	9	3,273	17,700	$12,150			$12,150	$36,214	$9,756	$979	$1,488	$10,850	$59,287
2017	9	3,298	17,661	$12,150			$12,150	$36,134	$9,734	$985	$1,891	$10,850	$59,594
2018	6	3,660	17,262	$8,100			$8,100	$35,317	$9,514	$1,072	$2,252	$10,850	$59,005
2019	0	4,262	15,732	$0			$0	$32,187	$8,671	$1,216	$1,961	$10,850	$54,885
2020	0	4,692	13,979	$0			$0	$28,600	$7,704	$1,319	$1,536	$10,850	$50,009
2021	0	4,704	13,916	$0			$0	$28,471	$7,670	$1,322	$1,386	$10,850	$49,699
2022	0	4,571	14,656	$0			$0	$29,985	$8,078	$1,290	$1,639	$10,850	$51,842
2023	0	4,369	13,758	$0			$0	$28,147	$7,583	$1,242	$1,715	$10,850	$49,536
2024	0	3,888	10,248	$0			$0	$20,967	$5,648	$1,126	$1,481	$10,850	$40,072
2025	0	3,769	12,526	$0			$0	$25,626	$6,903	$1,098	$1,397	$10,850	$45,875
2026	0	3,588	15,420	$0			$0	$31,548	$8,499	$1,055	$1,300	$10,850	$53,252
2027	0	3,380	17,405	$0			$0	$35,610	$9,593	$1,005	$1,356	$10,850	$58,413
2028	0	3,265	17,563	$0			$0	$35,934	$9,680	$977	$1,812	$10,850	$59,253
2029	0	3,371	17,224	$0			$0	$35,240	$9,493	$1,003	$2,140	$22,850	$70,726
Totals	240	40,328,706	151,590,051	$324,000	$80,158	$180,000	$584,158	$849,708	$228,901	$32,320	$45,753	$337,500	$1,494,182

Appendix E

Gas Cap Effect Simulation Data Set and Results, Commercial Plant Utilization and Detailed Plant Bitumen Forecasts and Undiscounted Costs for Clearwater Wolf Lake

```
**  SOURCE DATA SET: WOLF LAKE CLEARWATER CASE STUDY - BASE CASE
**  CMG STARS SIMULATION
**
**  No Gas Cap (Base Case run)
**  2D Run assuming a Live Oil (5.7 mol % Solution Gas)
**  Model Dimensions: 1490 m x 1000 m x 72 m
**  1000 m Horizontal Wells and 52 m of Pay above Producer Wells
**  Initial Reservoir Pressure = 2500 kPa
**  Full Scale Pattern Simulation with 3 Well Pairs (Well Pair 1 assumes perfect
 symmetry)
**  Inter-Well Distance is 90 m and Injector/Producer Vertical Spacing is 6.5 m
**  Grid Block thickness is variable in i-direction (ranging from 2 m to 128 m),

**  j-direction consists of a single slab of 1000 m thickness and k-direction co
nsists of
**  a constant 2 m thickness
**  Input and Output Units are SI; and time basis is days
**
**  ==============  INPUT/OUTPUT CONTROL  ======================

*filename *index-in 'Wolf_Lake_Base_NonDep.irf' *main-results-in

*title1 'Joint ADOE-EUB SAGD Study'
*title2 'Case Study: Wolf Lake Clearwater'
*title3 'Pattern Simulation'

**restart

*maxerror 1
*wrst *time

*prntorien 2 0
*outprn *grid *pres *temp *sw *so *sg *x *y
*outprn *well *brief
*wsrf *grid *time
*outsrf *grid *pres *temp *sw *so *sg *x *y

** ======================== GRID AND RESERVOIR DEFINITION ================

*grid *cart 145 1 36

*kdir *up

*di *ivar 115*2.0 5*4.0 5*8.0 5*16.0 5*32.0 5*64.0 5*128.0

*dj *con 1000.0

*dk *kvar 36*2.0

*vamod 2 0.5 1.0 0.5 0.5 *9p 1.0 1.0
*vatype *ivar 2 144*1.0

*dtop *con 420.0
```

```
*por *ijk
1:145 1 1:6       0.30
1:145 1 7:9       0.30
1:3   1 10        0.00
4:7   1 10        0.30
8:13  1 10        0.00
14:17 1 10        0.32
18:23 1 10        0.00
24:27 1 10        0.30
28:33 1 10        0.00
34:37 1 10        0.30
38:43 1 10        0.00
44:47 1 10        0.30
48:53 1 10        0.00
54:57 1 10        0.30
58:63 1 10        0.00
64:67 1 10        0.30
68:73 1 10        0.00
74:77 1 10        0.30
78:83 1 10        0.00
84:87 1 10        0.30
88:93 1 10        0.00
94:97 1 10        0.30
98:103 1 10       0.00
104:107 1 10      0.30
108:113 1 10      0.00
114:117 1 10      0.30
118:123 1 10      0.00
124:127 1 10      0.30
128:133 1 10      0.00
134:137 1 10      0.30
138:143 1 10      0.00
144:145 1 10      0.30
1:145   1 11:15   0.30
1:145   1 16:20   0.30
1:145   1 21:27   0.28
1:3   1 28        0.00
4:7   1 28        0.30
8:13  1 28        0.00
14:17 1 28        0.32
18:23 1 28        0.00
24:27 1 28        0.30
28:33 1 28        0.00
34:37 1 28        0.30
38:43 1 28        0.00
44:47 1 28        0.30
48:53 1 28        0.00
54:57 1 28        0.30
58:63 1 28        0.00
64:67 1 28        0.30
68:73 1 28        0.00
74:77 1 28        0.30
78:83 1 28        0.00
84:87 1 28        0.30
88:93 1 28        0.00
94:97 1 28        0.30
98:103 1 28       0.00
104:107 1 28      0.30
```

File: Wolf_Lake_Study.dat 1

```
100:113 1 28      0.00
114:117 1 28      0.30
118:123 1 28      0.00
124:127 1 28      0.30
128:133 1 28      0.00
134:137 1 28      0.30
138:143 1 28      0.00
144:145 1 28      0.30
1:145   1 29:31   0.30
1:3   1 32        0.00
4:7   1 32        0.30
8:13  1 32        0.00
14:17 1 32        0.32
18:23 1 32        0.00
24:27 1 32        0.30
28:33 1 32        0.00
34:37 1 32        0.30
38:43 1 32        0.00
44:47 1 32        0.30
48:53 1 32        0.00
54:57 1 32        0.30
58:63 1 32        0.00
64:67 1 32        0.30
68:73 1 32        0.00
74:77 1 32        0.30
78:83 1 32        0.00
84:87 1 32        0.30
88:93 1 32        0.00
94:97 1 32        0.30
98:103 1 32       0.00
104:107 1 32      0.30
108:113 1 32      0.00
114:117 1 32      0.30
118:123 1 32      0.00
124:127 1 32      0.30
128:133 1 32      0.00
134:137 1 32      0.30
138:143 1 32      0.00
144:145 1 32      0.30
1:145   1 33      0.30
1:145   1 34:35   0.30
1:145   1 36      0.24
```

```
*permi *ijk
1:145 1 1:6       650
1:145 1 7:9       2000
1:3   1 10        0.00
4:7   1 10        3300
8:13  1 10        0.00
14:17 1 10        3300
18:23 1 10        0.00
24:27 1 10        3300
28:33 1 10        0.00
34:37 1 10        3300
38:43 1 10        0.00
44:47 1 10        3300
48:53 1 10        0.00
54:57 1 10        3300
58:63 1 10        0.00
64:67 1 10        3300
68:73 1 10        0.00
74:77 1 10        3300
78:83 1 10        0.00
84:87 1 10        3300
88:93 1 10        0.00
94:97 1 10        3300
98:103 1 10       0.00
104:107 1 10      3300
108:113 1 10      0.00
114:117 1 10      3300
118:123 1 10      0.00
124:127 1 10      3300
128:133 1 10      0.00
134:137 1 10      3300
138:143 1 10      0.00
144:145 1 10      3300
1:145   1 11:15   3300
1:145   1 16:20   4000
1:145   1 21:27   3600
1:3   1 28        0.00
4:7   1 28        8500
8:13  1 28        0.00
14:17 1 28        8500
18:23 1 28        0.00
24:27 1 28        8500
28:33 1 28        0.00
34:37 1 28        8500
38:43 1 28        0.00
44:47 1 28        8500
48:53 1 28        0.00
54:57 1 28        8500
58:63 1 28        0.00
64:67 1 28        8500
68:73 1 28        0.00
74:77 1 28        8500
78:83 1 28        0.00
84:87 1 28        8500
88:93 1 28        0.00
94:97 1 28        8500
98:103 1 28       0.00
104:107 1 28      8500
```

```
100:113 1 20      0.00
114:117 1 20      8500
110:123 1 20      0.00
124:127 1 20      8500
120:133 1 20      0.00
134:137 1 20      8500
130:143 1 20      0.00
144:145 1 20      8500
1:145   1 29:31   8500
1:3   1 32        0.00
4:7   1 32        8000
8:13  1 32        0.00
14:17 1 32        8000
18:23 1 32        0.00
24:27 1 32        8000
28:33 1 32        0.00
34:37 1 32        8000
38:43 1 32        0.00
44:47 1 32        8000
48:53 1 32        0.00
54:57 1 32        8000
58:63 1 32        0.00
64:67 1 32        8000
68:73 1 32        0.00
74:77 1 32        8000
78:83 1 32        0.00
84:87 1 32        8000
88:93 1 32        0.00
94:97 1 32        8000
98:103 1 32       0.00
104:107 1 32      8000
108:113 1 32      0.00
114:117 1 32      8000
118:123 1 32      0.00
124:127 1 32      8000
128:133 1 32      0.00
134:137 1 32      8000
138:143 1 32      0.00
144:145 1 32      8000
1:145   1 33      8000
1:145   1 34:35   8000
1:145   1 36      400
```

```
*permj *ijk
1:145 1 1:6       650
1:145 1 7:9       2000
1:3   1 10        0.00
4:7   1 10        3300
8:13  1 10        0.00
14:17 1 10        3300
18:23 1 10        0.00
24:27 1 10        3300
28:33 1 10        0.00
34:37 1 10        3300
38:43 1 10        0.00
44:47 1 10        3300
48:53 1 10        0.00
54:57 1 10        3300
58:63 1 10        0.00
64:67 1 10        3300
68:73 1 10        0.00
74:77 1 10        3300
78:83 1 10        0.00
84:87 1 10        3300
88:93 1 10        0.00
94:97 1 10        3300
98:103 1 10       0.00
104:107 1 10      3300
108:113 1 10      0.00
114:117 1 10      3300
118:123 1 10      0.00
124:127 1 10      3300
128:133 1 10      0.00
134:137 1 10      3300
138:143 1 10      0.00
144:145 1 10      3300
1:145   1 11:15   3300
1:145   1 16:20   4000
1:145   1 21:27   3600
1:3   1 20        0.00
4:7   1 20        8500
8:13  1 20        0.00
14:17 1 20        8500
18:23 1 20        0.00
24:27 1 20        8500
28:33 1 20        0.00
34:37 1 20        8500
38:43 1 20        0.00
44:47 1 20        8500
48:53 1 20        0.00
54:57 1 20        8500
58:63 1 20        0.00
64:67 1 20        8500
68:73 1 20        0.00
74:77 1 20        8500
78:83 1 20        0.00
84:87 1 20        8500
88:93 1 20        0.00
94:97 1 20        8500
98:103 1 20       0.00
104:107 1 20      8500
```

File: Wolf_Lake_Study.dat 3

```
100:113 1 28      0.00
114:117 1 28      8500
110:123 1 28      0.00
124:127 1 28      8500
120:133 1 28      0.00
134:137 1 28      8500
130:143 1 28      0.00
144:145 1 28      8500
1:145   1 29:31   8500
1:3   1 32        0.00
4:7   1 32        8000
8:13  1 32        0.00
14:17 1 32        8000
10:23 1 32        0.00
24:27 1 32        8000
20:33 1 32        0.00
34:37 1 32        8000
30:43 1 32        0.00
44:47 1 32        8000
40:53 1 32        0.00
54:57 1 32        8000
50:63 1 32        0.00
64:67 1 32        8000
60:73 1 32        0.00
74:77 1 32        8000
70:83 1 32        0.00
84:87 1 32        8000
80:93 1 32        0.00
94:97 1 32        8000
90:103 1 32       0.00
104:107 1 32      8000
100:113 1 32      0.00
114:117 1 32      8000
110:123 1 32      0.00
124:127 1 32      8000
120:133 1 32      0.00
134:137 1 32      8000
130:143 1 32      0.00
144:145 1 32      8000
1:145   1 33      8000
1:145   1 34:35   8000
1:145   1 36      400
```

```
*permk *ijk
1:145 1 1:6       195       **permk = 0.3*permi
1:145 1 7:9       600
1:3   1 10        0.00
4:7   1 10        990
8:13  1 10        0.00
14:17 1 10        990
18:23 1 10        0.00
24:27 1 10        990
28:33 1 10        0.00
34:37 1 10        990
38:43 1 10        0.00
44:47 1 10        990
48:53 1 10        0.00
54:57 1 10        990
58:63 1 10        0.00
64:67 1 10        990
68:73 1 10        0.00
74:77 1 10        990
78:83 1 10        0.00
84:87 1 10        990
88:93 1 10        0.00
94:97 1 10        990
98:103 1 10       0.00
104:107 1 10      990
108:113 1 10      0.00
114:117 1 10      990
118:123 1 10      0.00
124:127 1 10      990
128:133 1 10      0.00
134:137 1 10      990
138:143 1 10      0.00
144:145 1 10      990
1:145   1 11:15   990
1:145   1 16:20   1200
1:145   1 21:27   1080
1:3   1 20        0.00
4:7   1 20        2550
8:13  1 20        0.00
14:17 1 20        2550
18:23 1 20        0.00
24:27 1 20        2550
28:33 1 20        0.00
34:37 1 20        2550
38:43 1 20        0.00
44:47 1 20        2550
48:53 1 20        0.00
54:57 1 20        2550
58:63 1 20        0.00
64:67 1 20        2550
68:73 1 20        0.00
74:77 1 20        2550
78:83 1 20        0.00
84:87 1 20        2550
88:93 1 20        0.00
94:97 1 20        2550
98:103 1 20       0.00
104:107 1 20      2550
```

```
108:113 1 20      0.00
114:117 1 20      2550
118:123 1 20      0.00
124:127 1 20      2550
128:133 1 20      0.00
134:137 1 20      2550
138:143 1 20      0.00
144:145 1 20      2550
1:145   1 29:31   2550
1:3   1 32        0.00
4:7   1 32        2400
8:13  1 32        0.00
14:17 1 32        2400
18:23 1 32        0.00
24:27 1 32        2400
28:33 1 32        0.00
34:37 1 32        2400
38:43 1 32        0.00
44:47 1 32        2400
48:53 1 32        0.00
54:57 1 32        2400
58:63 1 32        0.00
64:67 1 32        2400
68:73 1 32        0.00
74:77 1 32        2400
78:83 1 32        0.00
84:87 1 32        2400
88:93 1 32        0.00
94:97 1 32        2400
98:103 1 32       0.00
104:107 1 32      2400
108:113 1 32      0.00
114:117 1 32      2400
118:123 1 32      0.00
124:127 1 32      2400
128:133 1 32      0.00
134:137 1 32      2400
138:143 1 32      0.00
144:145 1 32      2400
1:145   1 33      2400
1:145   1 34:35   2400
1:145   1 36      400

*cpor 0.45e-6 *prpor 100.0

*rockcp 2.35e6
*cpc    17.0
*thconr 1.469e5
*thconw 5.350e4
*thcono 1.200e4
*thcong 140.0
*thconmix *simple

*hlossprop *overbur 2.350e6 1.496e5 *hlosst 16.0 *hlosstdiff 0.1
*hlossprop *underbur 2.350e6 1.496e5 *hlosst 16.0 *hlosstdiff 0.1
```

```
**================== FLUID DEFINITIONS ==========================

*model 3 3 3

*compname       'WATER'         'OIL'           'CH4'
**              ------------------------------------------------
*cmm            0               0.5             0.01604
*pcrit          0               1360.0          4600.00
*tcrit          0               624.65          -82.55

*molden         0               1950.0          62500.0
*cp             0               3.40e-6         5.5e-7
*ct1            0               8.48e-4         8.0e-4
*ct2            0               0               0

*kv1            0               0               31914.0
*kv2            0               0               0
*kv3            0               0               0
*kv4            0               0               -33.067
*kv5            0               0               -27.71

*cpl1           0               1060            67.2
*cpgl           0               841             35.2
*hvapr          0               1346            1770.0

*visctable

** temp

        12.0            0       60590           0
        30.0            0       7000            0
        40.0            0       2261            0
        50.0            0       1153            0
        60.0            0       558             0
        70.0            0       296.4           0
        80.0            0       170.3           0
       100.0            0        68.14          0
       120.0            0        33.25          0
       140.0            0        18.83          0
       160.0            0        11.94          0
       180.0            0         8.256         0
       200.0            0         6.106         0
       220.0            0         4.761         0
       240.0            0         3.872         0
       260.0            0         3.257         0
       280.0            0         2.815         0
       300.0            0         2.488         0
      2000.0            0         2.488         0
```

```
**  ==============  ROCK-FLUID PROPERTIES  ======================

*rockfluid

*rpt 1

*swt

**   Sw          Krw            Krow
**   ----        ---------      -------
     0.2000      0.0000         1.0000
     0.2500      0.0000         0.7500
     0.3000      0.0000         0.5650
     0.3500      0.0000         0.4150
     0.4000      0.0000         0.3050
     0.4500      0.0000         0.2250
     0.5000      0.0000         0.1650
     0.5500      0.0000         0.1120
     0.6000      0.0000         0.0680
     0.6500      0.0150         0.0330
     0.7000      0.0500         0.0000
     1.0000      1.0000         0.0000

*slt

**   Sl          Krg            Krog
**   ------      --------       --------
     0.2000      1.0000         0.0000
     0.2500      0.8600         0.0000
     0.3000      0.7300         0.0000
     0.3500      0.6200         0.0000
     0.4000      0.5230         0.0000
     0.4500      0.4380         0.0000
     0.5000      0.3680         0.0000
     0.5500      0.3080         0.0000
     0.6000      0.2550         0.0000
     0.6500      0.1970         0.0000
     0.7000      0.1530         0.0125
     0.7500      0.1130         0.0160
     0.8000      0.0780         0.0210
     0.8500      0.0450         0.0282
     0.9000      0.0100         0.0374
     0.9500      0.0000         0.0500
     1.0000      0.0000         0.0680
```

```
*rpt 2

*swt

**   Sw          Krw            Krow
**   ----        ---------      -------
     0.2000      0.0000         1.0000
     0.2500      0.0000         0.7500
     0.3000      0.0000         0.5650
     0.3500      0.0000         0.4150
     0.4000      0.0000         0.3050
     0.4500      0.0000         0.2250
     0.5000      0.0024         0.1650
     0.5500      0.0075         0.1120
     0.6000      0.0172         0.0680
     0.6500      0.0325         0.0330
     0.7000      0.0500         0.0000
     1.0000      1.0000         0.0000
```

```
*slt

**   Sl          Krg          Krog
**  ------      --------     --------
    0.2000      1.0000       0.0000
    0.2500      0.8600       0.0000
    0.3000      0.7300       0.0000
    0.3500      0.6200       0.0000
    0.4000      0.5230       0.0000
    0.4500      0.4380       0.0000
    0.5000      0.3680       0.0000
    0.5500      0.3080       0.0142
    0.6000      0.2550       0.0210
    0.6500      0.1970       0.0315
    0.7000      0.1530       0.0438
    0.7500      0.1130       0.0600
    0.8000      0.0780       0.0790
    0.8500      0.0450       0.1050
    0.9000      0.0100       0.1280
    0.9500      0.0000       0.1640
    1.0000      0.0000       0.2250

*swr 0.40

*rpt 3

*swt

**   Sw          Krw          Krow
**  ----      ---------      -------
    0.2000      0.0000       1.0000
    0.2500      0.0000       0.7500
    0.3000      0.0000       0.5650
    0.3500      0.0015       0.4150
    0.4000      0.0040       0.3050
    0.4500      0.0080       0.2250
    0.5000      0.0130       0.1650
    0.5500      0.0195       0.1120
    0.6000      0.0280       0.0680
    0.6500      0.0375       0.0330
    0.7000      0.0500       0.0000
    1.0000      1.0000       0.0000

*slt

**   Sl          Krg          Krog
**  ------      --------     --------
    0.2000      1.0000       0.0000
    0.2500      0.8600       0.0000
    0.3000      0.7300       0.0000
    0.3500      0.6200       0.0000
    0.4000      0.5230       0.0150
    0.4500      0.4380       0.0330
    0.5000      0.3680       0.0530
    0.5500      0.3080       0.0780
    0.6000      0.2550       0.1060
    0.6500      0.1970       0.1410
    0.7000      0.1530       0.1810
    0.7500      0.1130       0.2300
    0.8000      0.0780       0.2760
    0.8500      0.0450       0.3290
    0.9000      0.0100       0.3900
    0.9500      0.0000       0.4610
    1.0000      0.0000       0.5650

*swr 0.60

*rpt 4

*swt

**   Sw          Krw          Krow
**  ----      ---------      -------
    0.2000      0.0000       1.0000
    0.2500      0.0006       0.7500
    0.3000      0.0013       0.5650
    0.3500      0.0024       0.4150
    0.4000      0.0035       0.3050
    0.4500      0.0060       0.2250
    0.5000      0.0090       0.1650
    0.5500      0.0140       0.1120
    0.6000      0.0200       0.0680
    0.6500      0.0300       0.0330
    0.7000      0.0500       0.0000
    1.0000      1.0000       0.0000


*slt

**   Sl          Krg          Krog
**  ------      --------     --------
    0.2000      1.0000       0.0000
    0.2500      0.8600       0.0000
    0.3000      0.7300       0.0150
    0.3500      0.6200       0.0340
    0.4000      0.5230       0.0560
    0.4500      0.4380       0.0880
    0.5000      0.3680       0.1260
    0.5500      0.3080       0.1700
    0.6000      0.2550       0.2200
    0.6500      0.1970       0.2750
    0.7000      0.1530       0.3400
    0.7500      0.1130       0.4180
    0.8000      0.0780       0.5020
    0.8500      0.0450       0.5960
    0.9000      0.0100       0.7120
    0.9500      0.0000       0.8420
    1.0000      0.0000       1.0000
```

```
*rpt 5

*swt

**   Sw          Krw          Krow
**   ----        ---------    -------
     0.2000      0.0000       1.0000
     0.2500      0.0000       0.7500
     0.3000      0.0013       0.5650
     0.3500      0.0033       0.4150
     0.4000      0.0060       0.3050
     0.4500      0.0100       0.2250
     0.5000      0.0148       0.1650
     0.5500      0.0208       0.1120
     0.6000      0.0288       0.0680
     0.6500      0.0375       0.0330
     0.7000      0.0500       0.0000
     1.0000      1.0000       0.0000

*slt

**   Sl          Krg          Krog
**   ------      --------     --------
     0.2000      1.0000       0.0000
     0.2500      0.8600       0.0000
     0.3000      0.7300       0.0000
     0.3500      0.6200       0.0150
     0.4000      0.5230       0.0340
     0.4500      0.4380       0.0600
     0.5000      0.3680       0.0910
     0.5500      0.3080       0.1260
     0.6000      0.2550       0.1700
     0.6500      0.1970       0.2190
     0.7000      0.1530       0.2700
     0.7500      0.1130       0.3260
     0.8000      0.0780       0.3940
     0.8500      0.0450       0.4660
     0.9000      0.0100       0.5510
     0.9500      0.0000       0.6400
     1.0000      0.0000       0.7500

*rpt 6

*swt

**   Sw          Krw          Krow
**   ----        ---------    -------
     0.3200      0.0000       1.0000
     0.4417      0.0025       0.6440
     0.5450      0.0100       0.3910
     0.6359      0.0330       0.1380
     0.6760      0.0530       0.0610
     0.7145      0.0730       0.0300
     0.7530      0.1130       0.0120
     0.7700      0.1200       0.0000

*slt

**   Sl          Krg          Krog
**   ------      --------     --------
     0.5400      0.5700       0.0000
     0.5685      0.5200       0.0160
     0.6183      0.4000       0.0500
     0.6639      0.2900       0.1000
     0.7113      0.2100       0.1500
     0.7596      0.1400       0.2200
     0.8070      0.0930       0.3000
     0.8543      0.0530       0.4400
     0.9016      0.0330       0.6000
     0.9299      0.0130       0.8400
     0.9399      0.0050       0.9300
     0.9500      0.0000       1.0000

*swr 0.40

*rpt 7

*swt

**   Sw          Krw          Krow
**   ------      -------      ------
     0.2000      0.0000       1.0000
     0.2500      0.0000       0.7500
     0.3000      0.0000       0.5650
     0.3500      0.0000       0.4150
     0.4000      0.0000       0.3050
     0.4500      0.0000       0.2250
     0.5000      0.0024       0.1650
     0.5500      0.0075       0.1120
     0.6000      0.0172       0.0680
     0.6500      0.0325       0.0330
     0.7000      0.0500       0.0000
     1.0000      1.0000       0.0000

*slt

**   sl          Krg          Krog
**   ------      -------      -------
     0.2000      1.0000       0.0000
     0.2500      0.8600       0.0000
     0.3000      0.7300       0.0000
     0.3500      0.6200       0.0000
     0.4000      0.5230       0.0000
     0.4500      0.4380       0.0000
     0.5000      0.3680       0.0000
     0.5500      0.3080       0.0142
     0.6000      0.2550       0.0210
     0.6500      0.1970       0.0315
     0.7000      0.1530       0.0438
     0.7500      0.1130       0.0600
     0.8000      0.0780       0.0790
     0.8500      0.0450       0.1050
     0.9000      0.0100       0.1280
     0.9500      0.0000       0.1640
```

```
   1.0000          0.0000          0.2250

*swr 0.50
```

```
*krtype *ijk
1:145 1 1:6       2
1:145 1 7:9       7
1:3   1 10        6
4:7   1 10        2
8:13  1 10        6
14:17 1 10        2
18:23 1 10        6
24:27 1 10        2
28:33 1 10        6
34:37 1 10        2
38:43 1 10        6
44:47 1 10        2
48:53 1 10        6
54:57 1 10        2
58:63 1 10        6
64:67 1 10        2
68:73 1 10        6
74:77 1 10        2
78:83 1 10        6
84:87 1 10        2
88:93 1 10        6
94:97 1 10        2
98:103 1 10       6
104:107 1 10      2
108:113 1 10      6
114:117 1 10      2
118:123 1 10      6
124:127 1 10      2
128:133 1 10      6
134:137 1 10      2
138:143 1 10      6
144:145 1 10      2
1:145   1 11:15   2
1:145   1 16:20   3
1:145   1 21:27   3
1:3   1 28        6
4:7   1 28        3
8:13  1 28        6
14:17 1 28        3
18:23 1 28        6
24:27 1 28        3
28:33 1 28        6
34:37 1 28        3
38:43 1 28        6
44:47 1 28        3
48:53 1 28        6
54:57 1 28        3
58:63 1 28        6
64:67 1 28        3
68:73 1 28        6
74:77 1 28        3
78:83 1 28        6
84:87 1 28        3
88:93 1 28        6
94:97 1 28        3
98:103 1 28       6
104:107 1 28      3
```

```
100:113 1 20      6
114:117 1 20      3
110:123 1 20      6
124:127 1 20      3
120:133 1 28      6
134:137 1 20      3
130:143 1 28      6
144:145 1 20      3
1:145   1 29:31   3
1:3   1 32        6
4:7   1 32        7
8:13  1 32        6
14:17 1 32        7
18:23 1 32        6
24:27 1 32        7
28:33 1 32        6
34:37 1 32        7
38:43 1 32        6
44:47 1 32        7
48:53 1 32        6
54:57 1 32        7
58:63 1 32        6
64:67 1 32        7
68:73 1 32        6
74:77 1 32        7
78:83 1 32        6
84:87 1 32        7
88:93 1 32        6
94:97 1 32        7
98:103 1 32       6
104:107 1 32      7
108:113 1 32      6
114:117 1 32      7
110:123 1 32      6
124:127 1 32      7
120:133 1 32      6
134:137 1 32      7
130:143 1 32      6
144:145 1 32      7
1:145   1 33      7
1:145   1 34:35   3
1:145   1 36      3
```

```
** ======================== INTIAL CONDITIONS ============================

*initial

*pres *con 2500.0

*temp *con 16.0

*sg *ijk 1:145 1 1:36   0.00

*sw *ijk
1:145 1 1:6       0.40
1:145 1 7:9       0.50
1:3   1 10        0.00
4:7   1 10        0.40
8:13  1 10        0.00
14:17 1 10        0.40
18:23 1 10        0.00
24:27 1 10        0.40
28:33 1 10        0.00
34:37 1 10        0.40
38:43 1 10        0.00
44:47 1 10        0.40
48:53 1 10        0.00
54:57 1 10        0.40
58:63 1 10        0.00
64:67 1 10        0.40
68:73 1 10        0.00
74:77 1 10        0.40
78:83 1 10        0.00
84:87 1 10        0.40
88:93 1 10        0.00
94:97 1 10        0.40
98:103 1 10       0.00
104:107 1 10      0.40
108:113 1 10      0.00
114:117 1 10      0.40
110:123 1 10      0.00
124:127 1 10      0.40
120:133 1 10      0.00
134:137 1 10      0.40
130:143 1 10      0.00
144:145 1 10      0.40
1:145   1 11:15   0.40
1:145   1 16:20   0.65
1:145   1 21:27   0.55
1:3   1 28        0.00
4:7   1 28        0.60
8:13  1 28        0.00
14:17 1 28        0.60
18:23 1 28        0.00
24:27 1 28        0.60
28:33 1 28        0.00
34:37 1 28        0.60
38:43 1 28        0.00
44:47 1 28        0.60
48:53 1 28        0.00
54:57 1 28        0.60
```

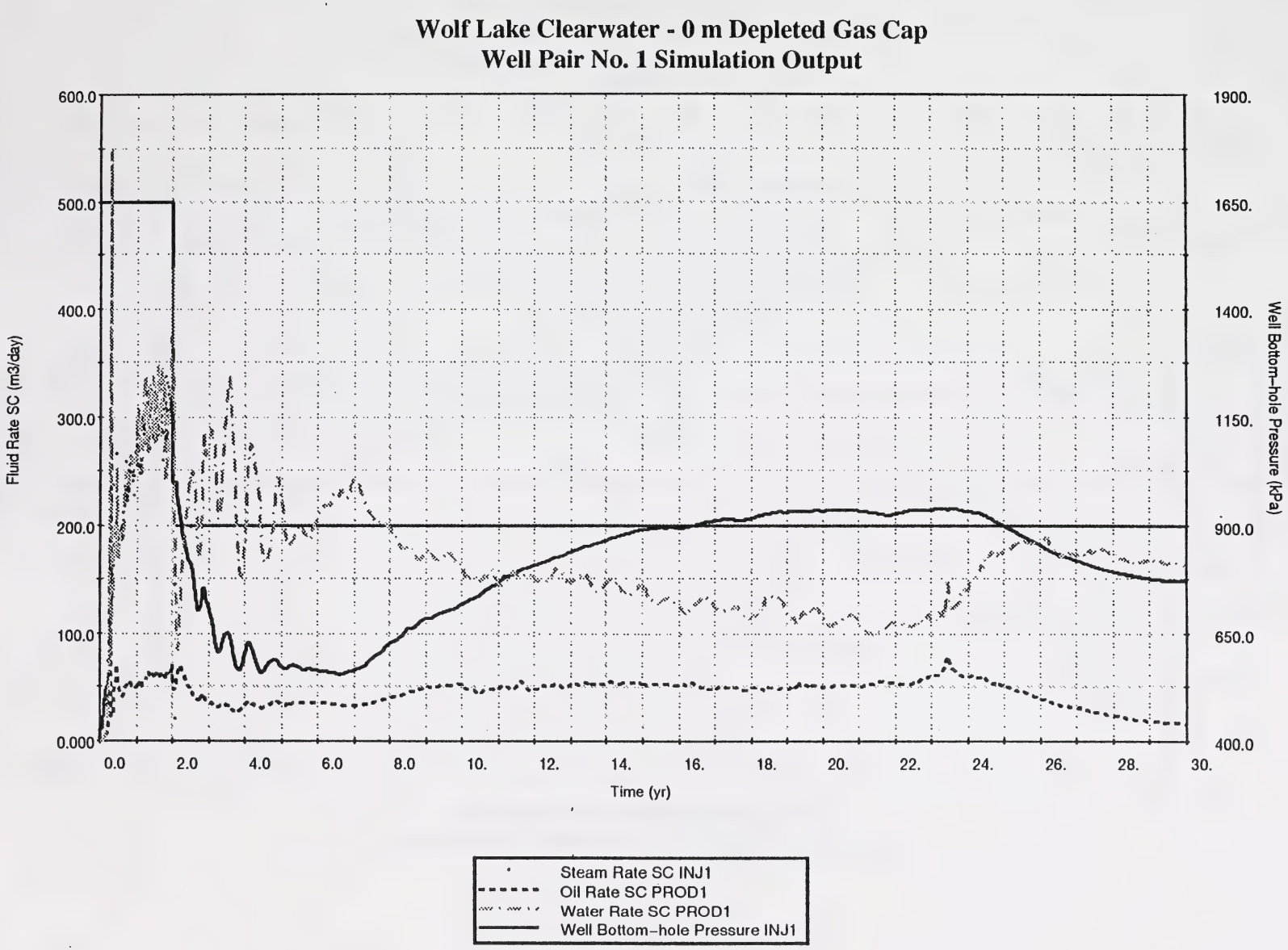
```
50:63 1 28        0.00
64:67 1 28        0.60
68:73 1 28        0.00
74:77 1 28        0.60
78:83 1 28        0.00
84:87 1 28        0.60
88:93 1 28        0.00
94:97 1 28        0.60
98:103 1 28       0.00
104:107 1 28      0.60
108:113 1 28      0.00
114:117 1 28      0.60
118:123 1 28      0.00
124:127 1 28      0.60
128:133 1 28      0.00
134:137 1 28      0.60
138:143 1 28      0.00
144:145 1 28      0.60
1:145   1 29:31   0.60
1:3   1 32        0.00
4:7   1 32        0.50
8:13  1 32        0.00
14:17 1 32        0.50
18:23 1 32        0.00
24:27 1 32        0.50
28:33 1 32        0.00
34:37 1 32        0.50
38:43 1 32        0.00
44:47 1 32        0.50
48:53 1 32        0.00
54:57 1 32        0.50
58:63 1 32        0.00
64:67 1 32        0.50
68:73 1 32        0.00
74:77 1 32        0.50
78:83 1 32        0.00
84:87 1 32        0.50
88:93 1 32        0.00
94:97 1 32        0.50
98:103 1 32       0.00
104:107 1 32      0.50
108:113 1 32      0.00
114:117 1 32      0.50
118:123 1 32      0.00
124:127 1 32      0.50
128:133 1 32      0.00
134:137 1 32      0.50
138:143 1 32      0.00
144:145 1 32      0.50
1:145   1 33      0.50
1:145   1 34:35   0.60
1:145   1 36      0.60

*molefrac *oil *con 0.0 0.943 0.057
*molefrac *gas *con 0.0 0.0   1.0
```

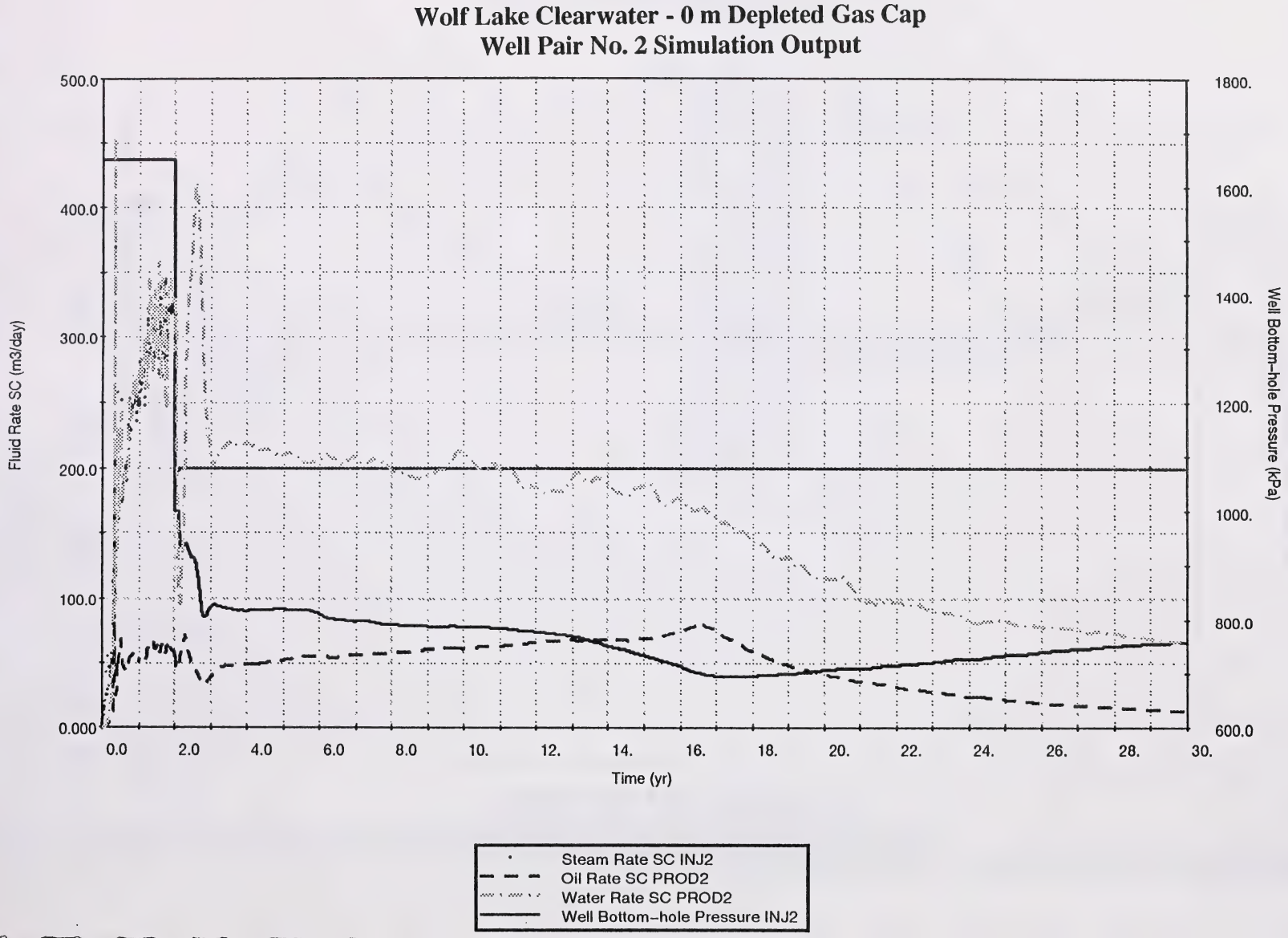
```
**  ==============  NUMERICAL CONTROL  ======================

*numerical

*aim            *on
*dtmax          15.00
*maxsteps       500000
*north          8
*itermax        60
*unrelax        -1
*sdegree        2
*sorder         rcmrb
*mintemp        1
*minpres        0.01
*norm           *press 400.0
                *satur 0.2
                *temp 50.0      *y      0.2     *x      0.2
*converge       *press 30.0
                *satur 0.04     *y      0.04    *x      0.04
                *temp 3.0
*pvtoscmax       4

**  ==============  RECURRENT DATA  ======================

*run
*date 2000 1 1    *dtwell 1.0E-2

*well 1 'INJ1'   *frac 0.500
*injector *mobweight 1
*tinjw 223.9 *qual 0.98
*operate *max *bhp 2500.
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 1
1:1 1:1 14
*uhtr *ijk
1:1 1:1 14       0.110e9
*tmpset *ijk
1:1 1:1 14        223.9

*well 2 'PROD1'    *frac 0.500
*producer 2
*operate *min *bhp 2000.0
*operate *max *steamtrap 10.0
*operate *min *bhp 2000.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 2
1:1  1:1  11
*uhtr *ijk
1:1  1:1  11     0.110e9
*tmpset *ijk
1:1  1:1  11     223.9
```

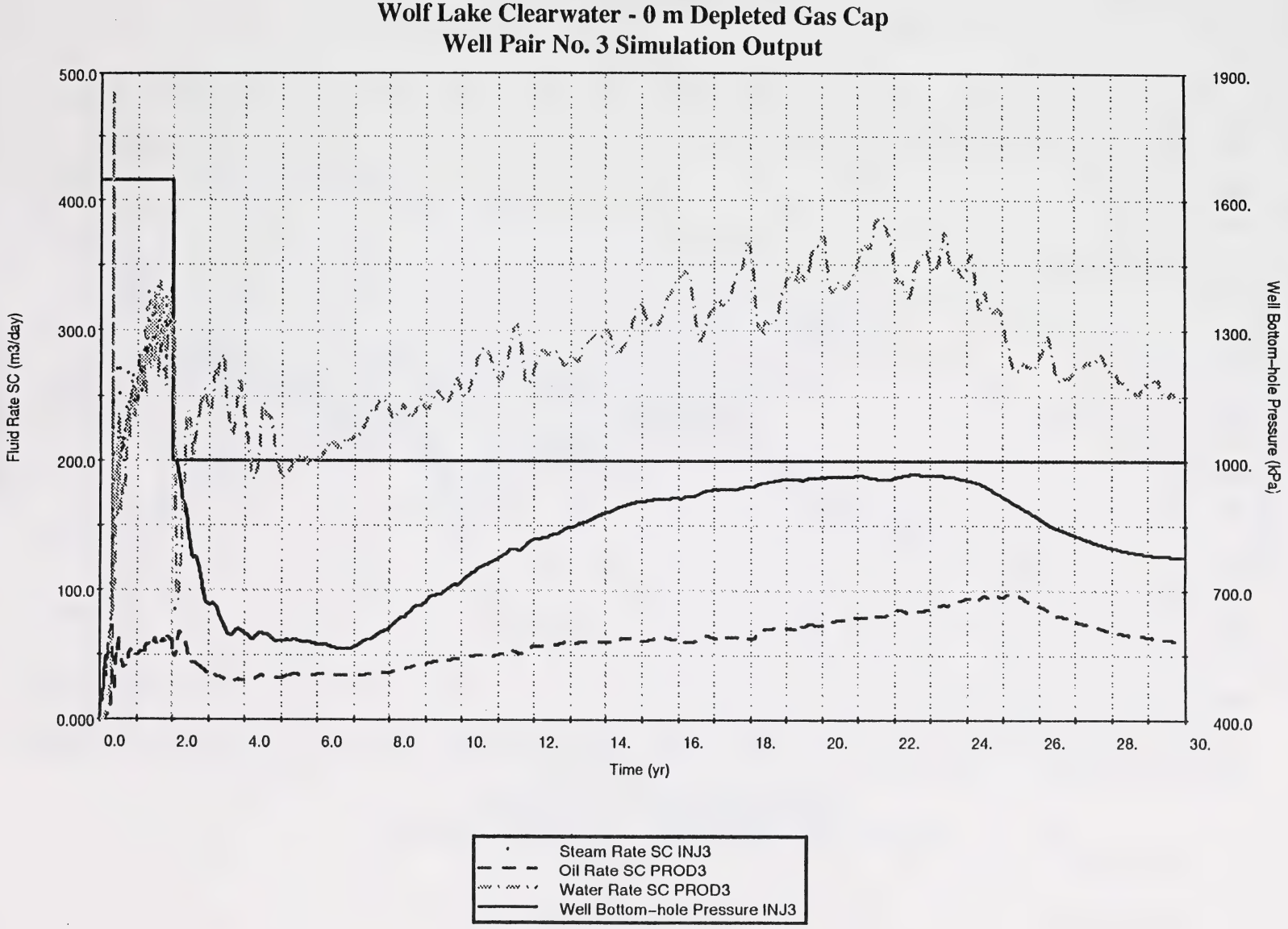
```
*well 3 'INJ2'
*injector *mobweight 3
*tinjw 223.9  *qual 0.98
*operate *max *bhp 2500.
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 3
46:46 1:1 14
*uhtr *ijk
46:46 1:1 14      0.110e9
*tmpset *ijk
46:46 1:1 14       223.9

*well 4 'PROD2'
*producer 4
*operate *min *bhp 2000.0
*operate *max *steamtrap 10.0
*operate *min *bhp 2000.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 4
46:46  1:1  11
*uhtr *ijk
46:46  1:1  11     0.110e9
*tmpset *ijk
46:46  1:1  11     223.9

*well 5 'INJ3'
*injector *mobweight 5
*tinjw 223.9  *qual 0.98
*operate *max *bhp 2500.
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 5
91:91 1:1 14
*uhtr *ijk
91:91 1:1 14       0.110e9
*tmpset *ijk
91:91 1:1 14       223.9

*well 6 'PROD3'
*producer 6
*operate *min *bhp 2000.0
*operate *max *steamtrap 10.0
*operate *min *bhp 2000.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 6
91:91  1:1  11
*uhtr *ijk
91:91  1:1  11     0.110e9
*tmpset *ijk
91:91  1:1  11     223.9
```

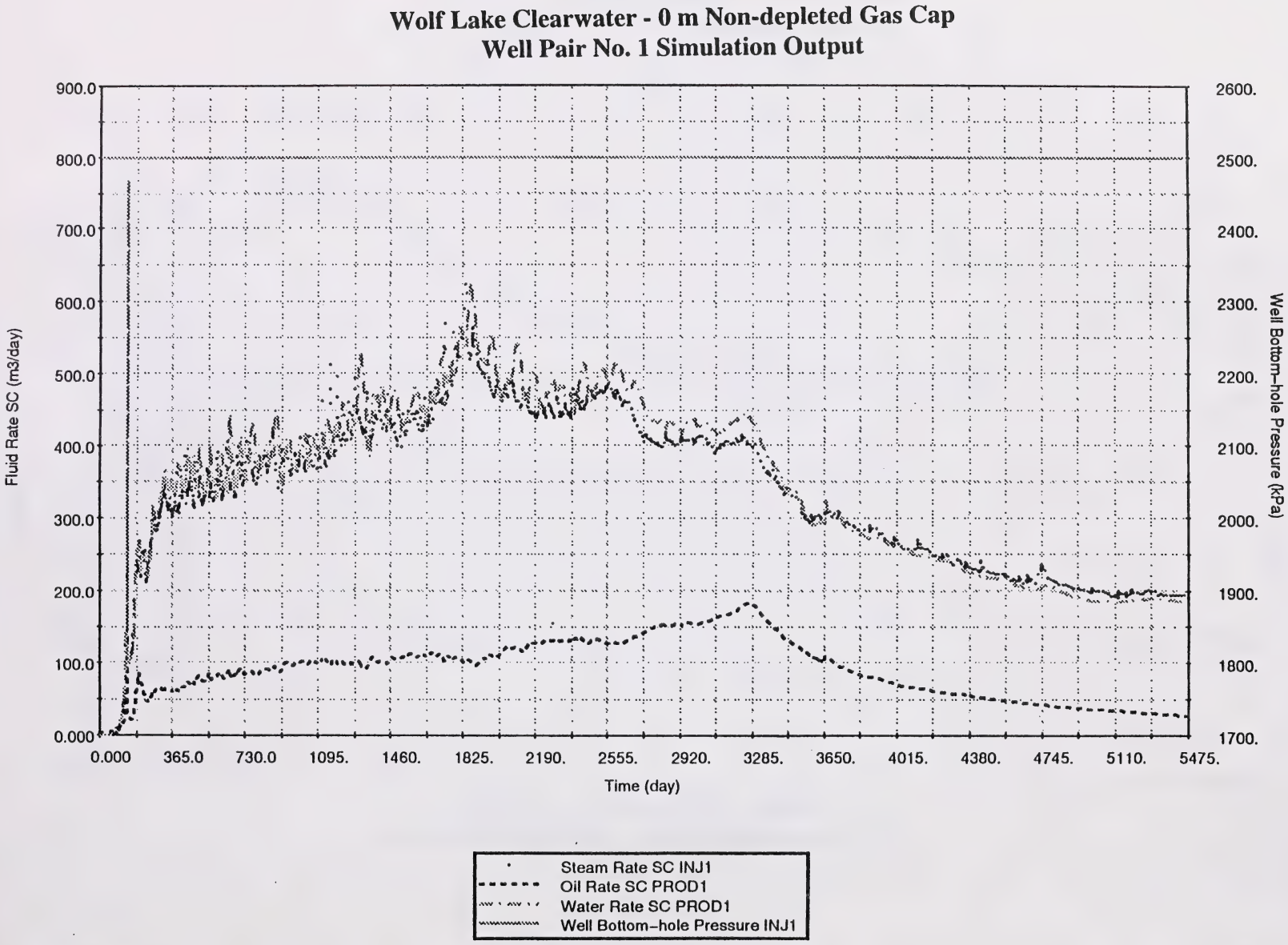
```
**well 7 'GAS'
**producer 7
**operate *min *bhp 2500.
**operate *max *gas 10000.
**operate *min *bhp 2500.
**geometry *m 0.110 0.363 0.5 0.0
**perf *geo 7
**180 1:2  14

*group  'INJ1' 'INJ2' 'INJ3' *attachto 'INJECTION'
*group  'PROD1' 'PROD2' 'PROD3' *attachto 'PRODUCTION'
```

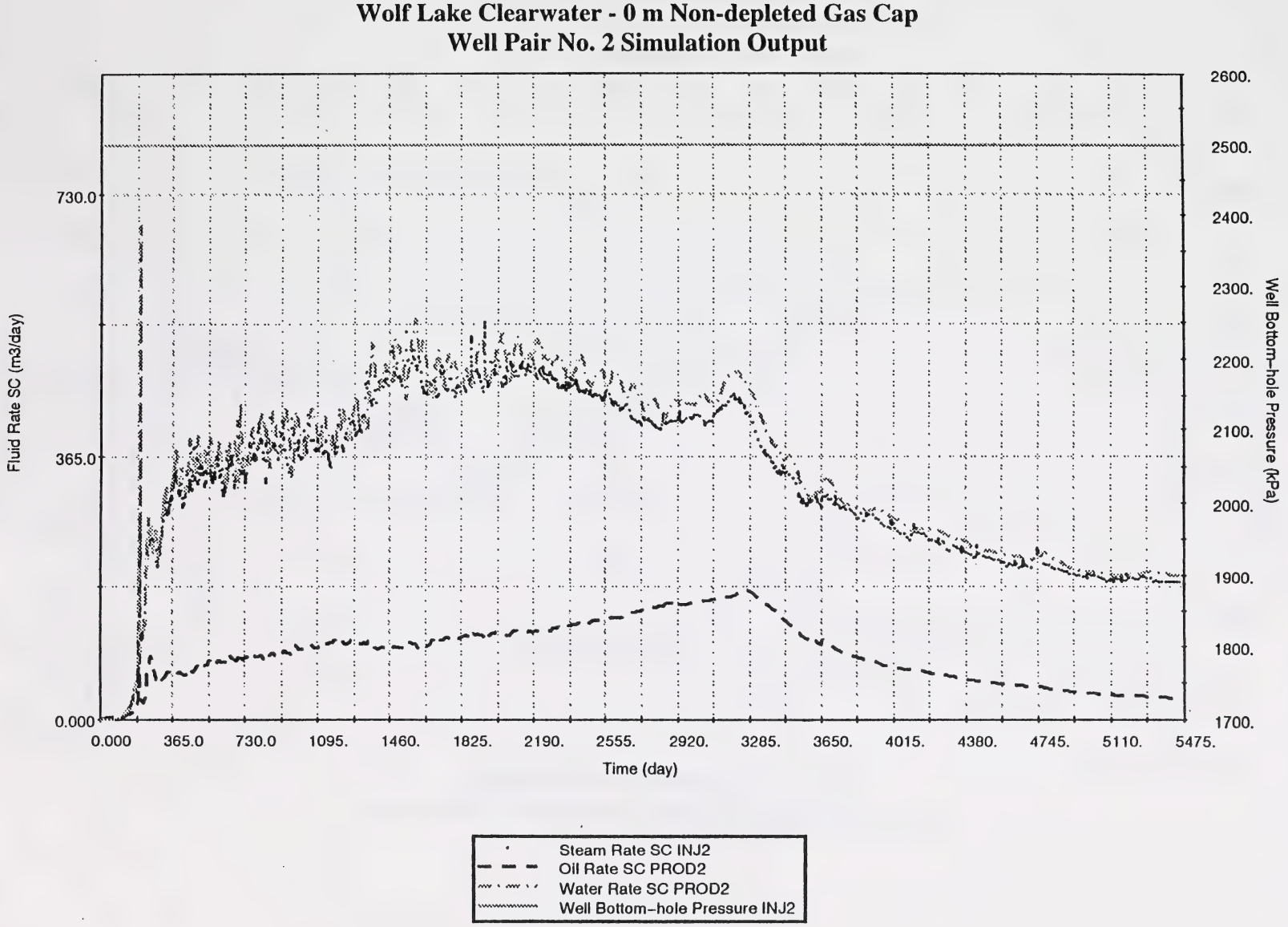
```
*dtmax 1.0

*time 10.0
*time 20.0
*time 36.5       **0.1 yrs
*time 50.0
*time 60.0
*dtmax 2.0
*time 70.0
*time 80.0
*time 81.0
*time 85.0
*time 90.0
*time 100.0
*time 105.0
*time 120.0
*time 150.0
*time 182.5
*time 210.0
*time 250.0
*time 300.0
*time 350.0
*time 365.0      **1.0 yr
*dtwell 0.001

*uhtr *ijk 1:1   1:1  14 0
*uhtr *ijk 1:1   1:1  11 0

*uhtr *ijk 46:46 1:1  14 0
*uhtr *ijk 46:46 1:1  11 0

*uhtr *ijk 91:91 1:1  14 0
*uhtr *ijk 91:91 1:1  11 0

*time 400.0
*time 438.0      **1.2 yrs
*time 547.5      **1.5 yrs
*time 657.0      **1.0 yrs
*time 730.0            **2.0 yrs
*dtmax 15.0
*time 803.0      **2.2 yrs
*time 912.5      **2.5 yrs
*time 1022.0     **2.8 yrs
*time 1095.0
**3.0 yrs
*time 1168.0     **3.2 yrs
*time 1277.5     **3.5 yrs
*time 1387.0     **3.8 yrs
*time 1460.0           **4.0 yrs
*time 1533.0     **4.3 yrs
*time 1565.0           ** 3 yrs operating time
*time 1642.5     **4.5 yrs
*time 1752.0     **4.8 yrs
*time 1825.0           ** 5.0 yrs
*time 1898.0     **5.2 yrs
*time 2007.5     **5.5 yrs
*time 2117.0     **5.8 yrs
*time 2190.0           ** 6.0 yrs
*time 2263.0     **6.2 yrs
*time 2372.5     **6.5 yrs
*time 2482.0     **6.8 yrs
*time 2555.0           ** 7.0 yrs
*time 2628.0     **7.2 yrs
*time 2701.0     **7.4 yrs
*time 2737.5     **7.5 yrs
*time 2847.0     **7.8 yrs
*time 2920.0           ** 8.0 yrs
*time 2993.0     **8.2 yrs
*time 3102.5     **8.5 yrs
*time 3212.0     **8.8 yrs
*time 3285.0           ** 9.0 yrs
*time 3358.0     **9.2 yrs
*time 3467.5     **9.5 yrs
*time 3650.0           ** 10.0 yrs
*time 3832.5
*time 4015.0
*time 4197.5
*time 4380.0
*time 4562.5
*time 4745.0
*time 4927.5
*time 5110.0
*time 5292.5
*time 5475.0
*time 5657.5
*time 5840.0
*time 6022.5
*time 6205.0
*time 6387.5
*time 6570.0
*time 6752.5
*time 6935.0
*time 7117.5
*time 7300.0

*stop
```

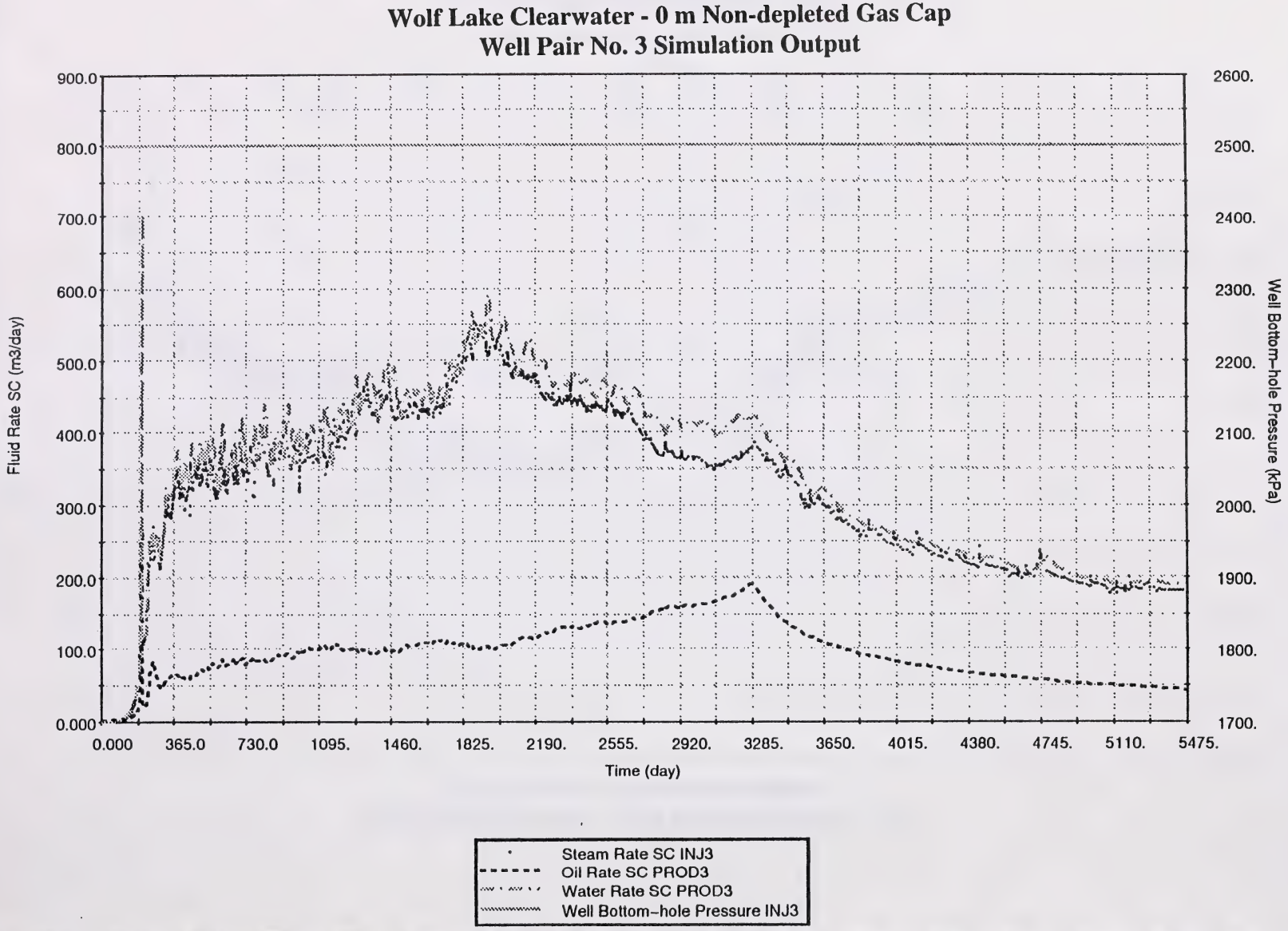

Wolf Lake Clearwater - 0 m Depleted Gas Cap
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
1900.
1650.
1400.
1150.
900.0
650.0
400.0
0.0
2.0
4.0
6.0
8.0
10.
12.
14.
16.
18.
20.
22.
24.
26.
28.
30.
Time (yr)
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1

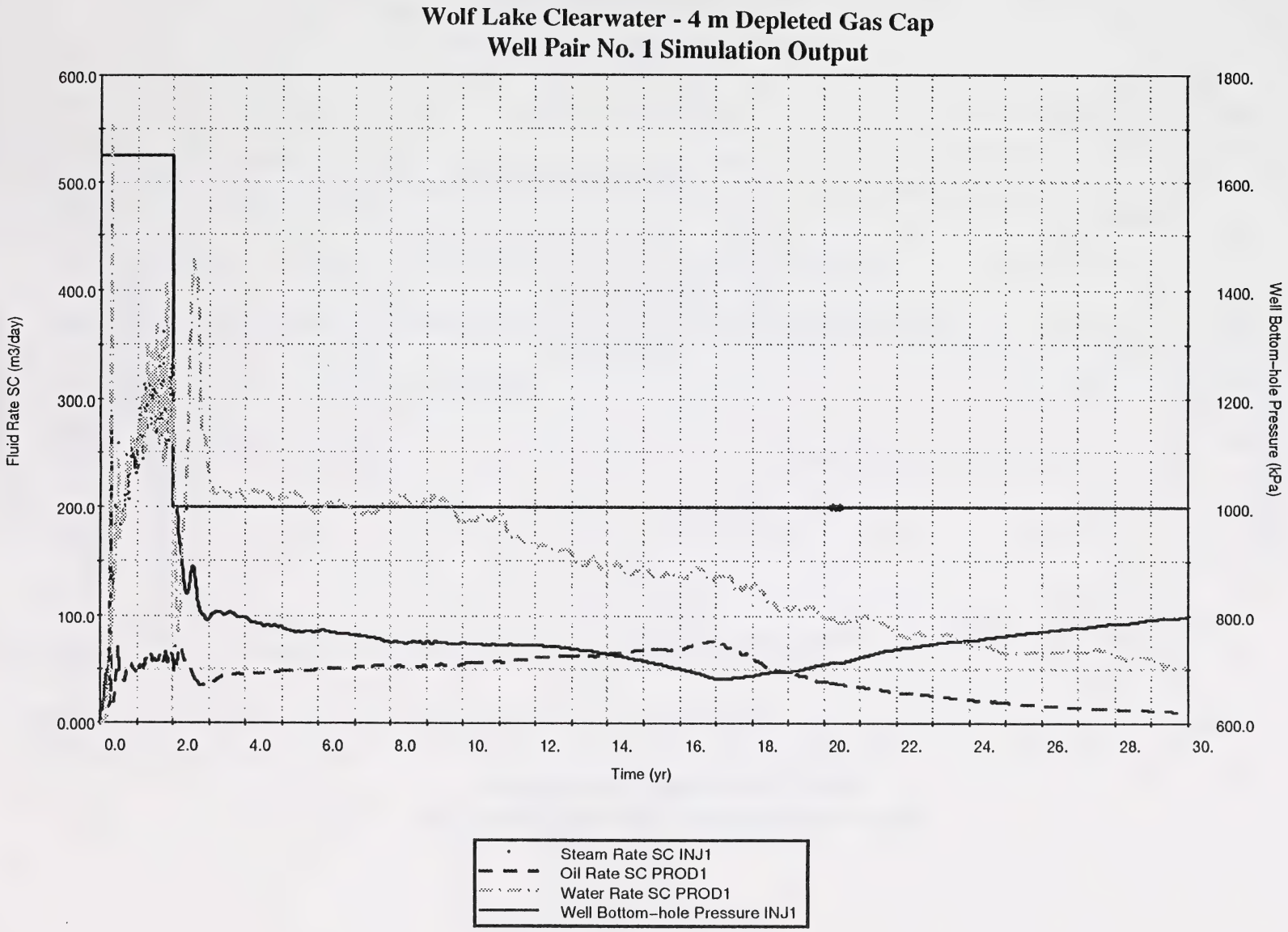

Wolf Lake Clearwater - 0 m Depleted Gas Cap
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
1800.
1600.
1400.
1200.
1000.
800.0
600.0
0.0
2.0
4.0
6.0
8.0
10.
12.
14.
16.
18.
20.
22.
24.
26.
28.
30.
Time (yr)
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2

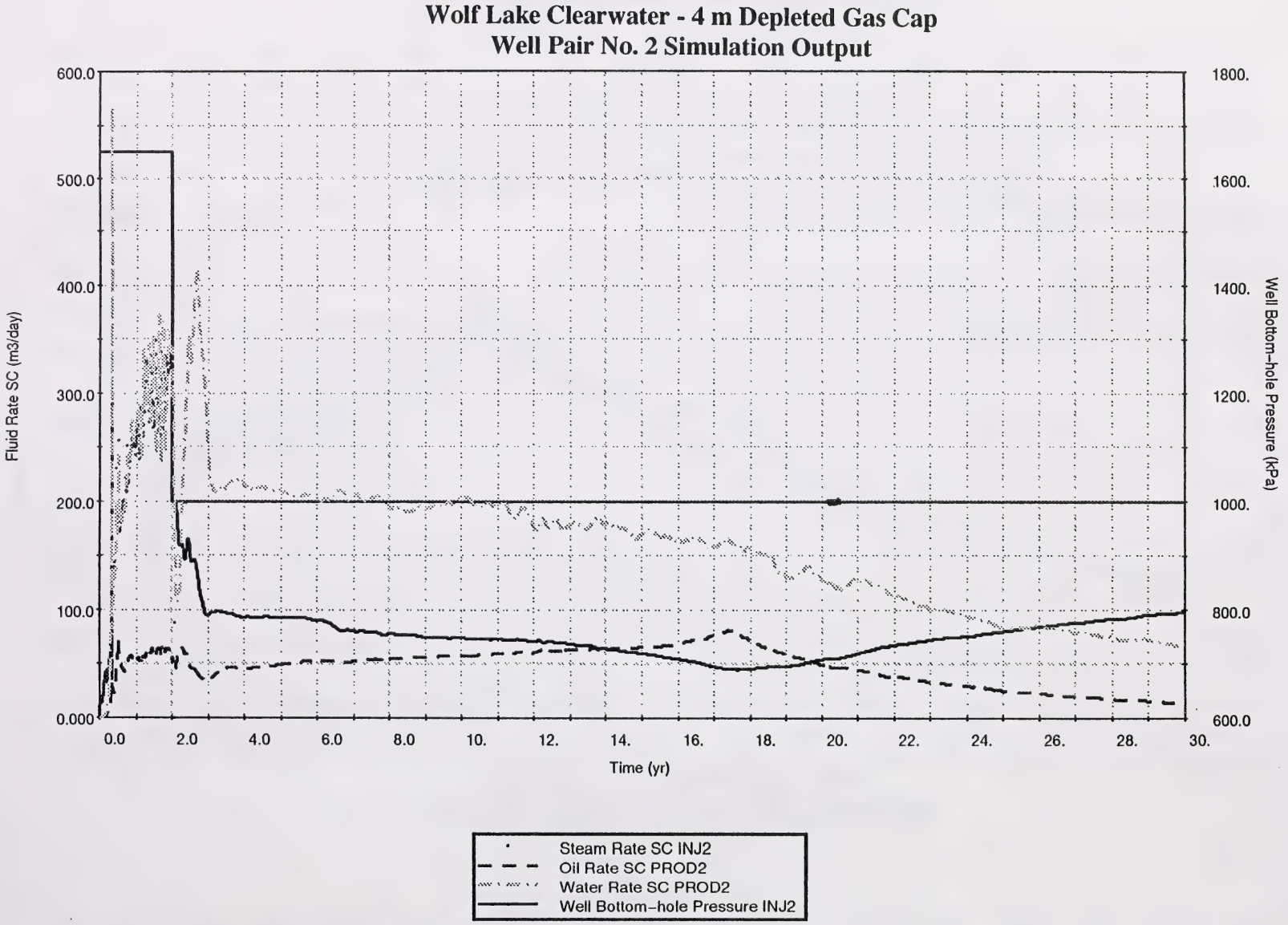

Wolf Lake Clearwater - 0 m Depleted Gas Cap
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
1900.
1600.
1300.
1000.
700.0
400.0
0.0
2.0
4.0
6.0
8.0
10.
12.
14.
16.
18.
20.
22.
24.
26.
28.
30.
Time (yr)
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3

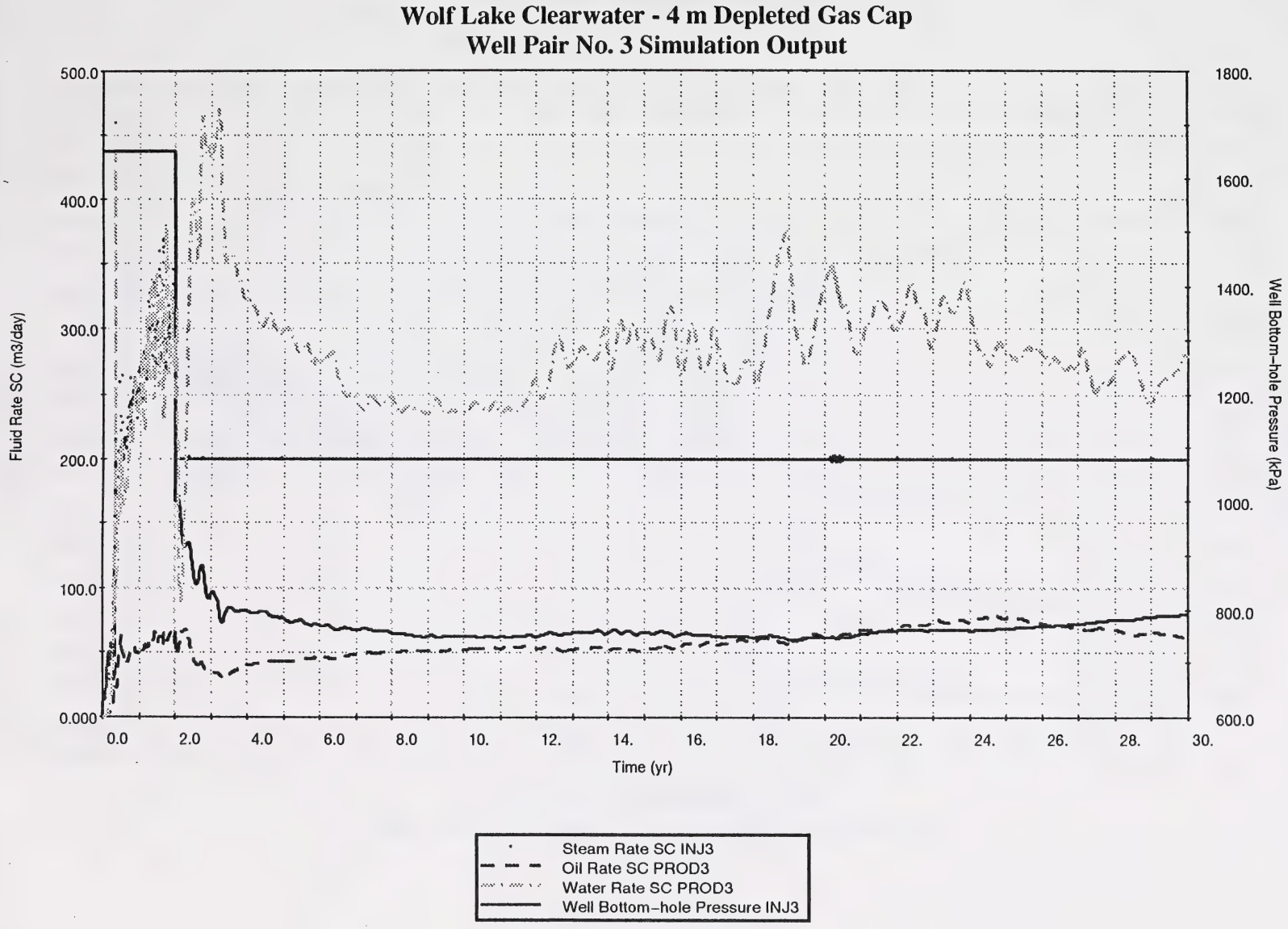

Wolf Lake Clearwater - 0 m Non-depleted Gas Cap
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
2600.
2500.
2400.
2300.
2200.
2100.
2000.
1900.
1800.
1700.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1

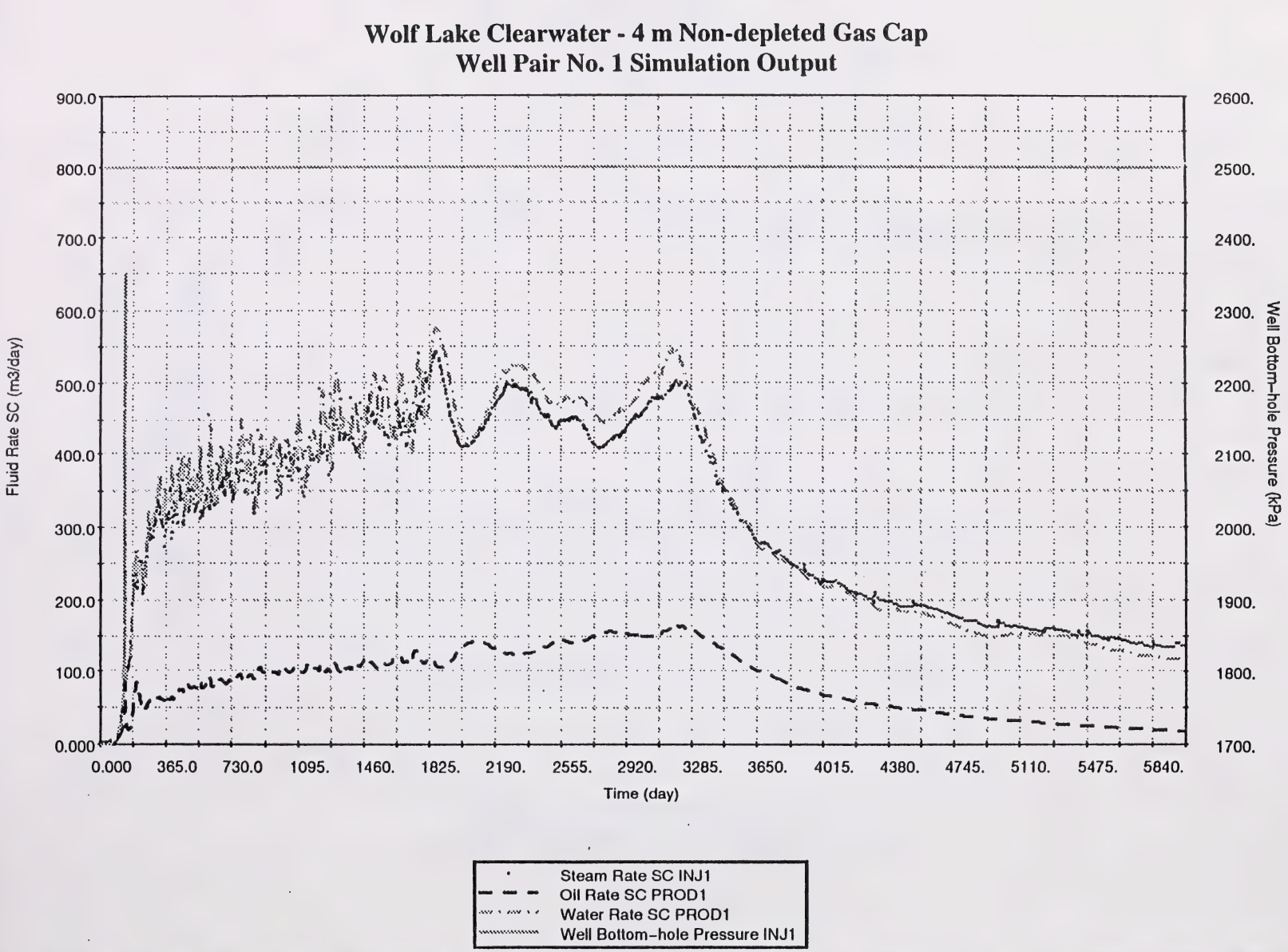

Wolf Lake Clearwater - 0 m Non-depleted Gas Cap
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
730.0
365.0
0.000
Well Bottom-hole Pressure (kPa)
2600.
2500.
2400.
2300.
2200.
2100.
2000.
1900.
1800.
1700.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2

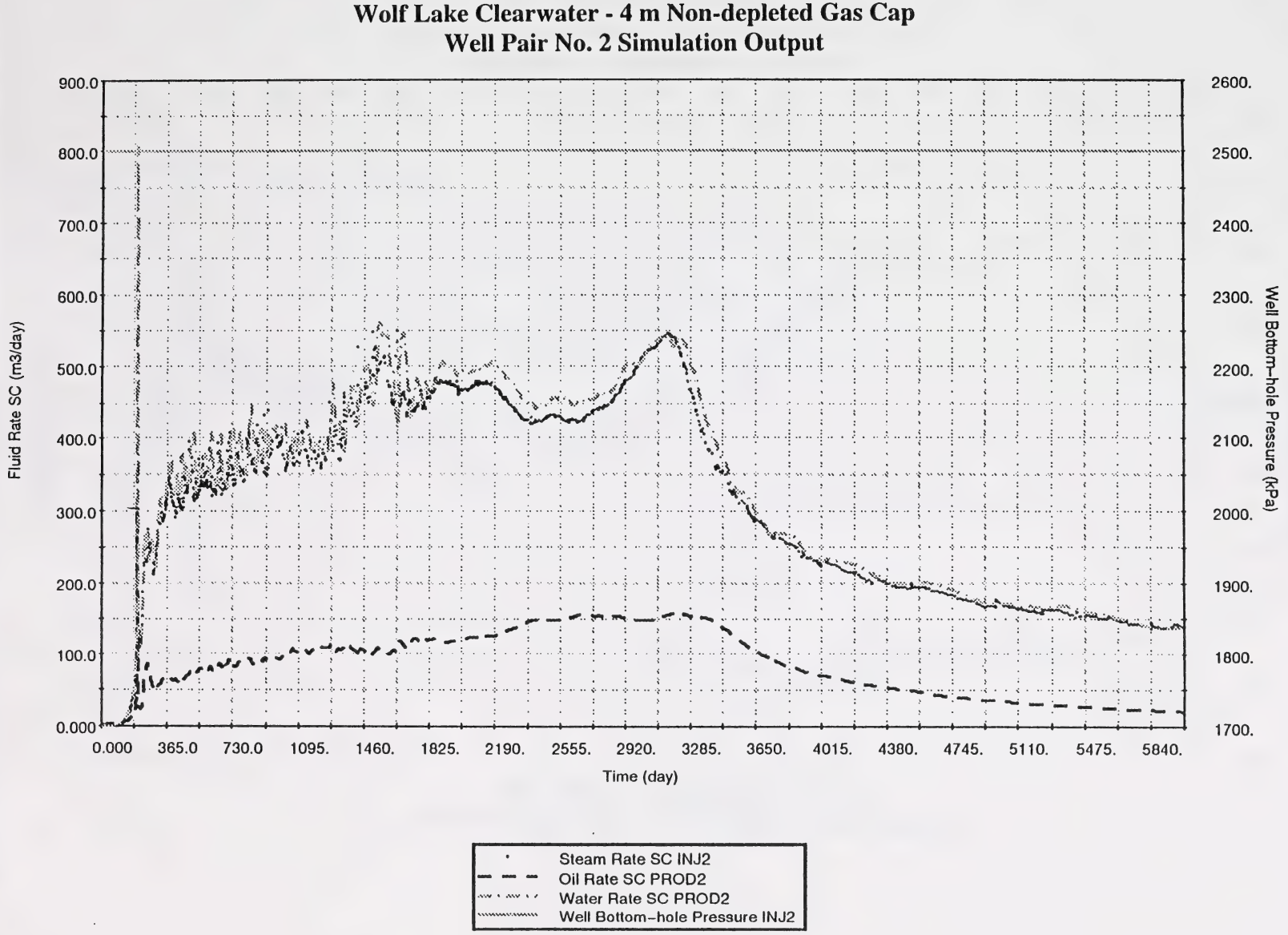

Wolf Lake Clearwater - 0 m Non-depleted Gas Cap
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
2600.
2500.
2400.
2300.
2200.
2100.
2000.
1900.
1800.
1700.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3

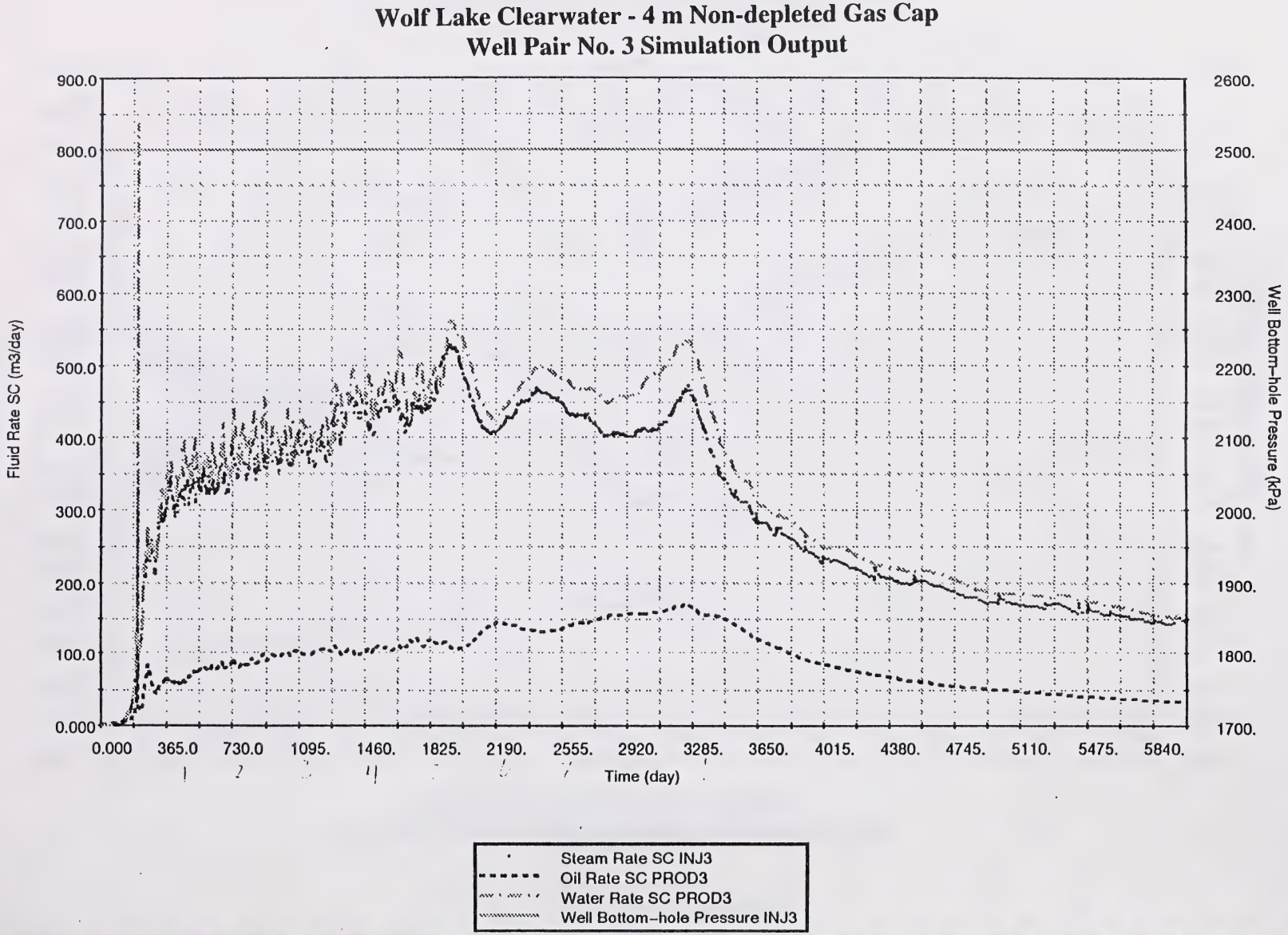

Wolf Lake Clearwater - 4 m Depleted Gas Cap
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
1800.
1600.
1400.
1200.
1000.
800.0
600.0
0.0
2.0
4.0
6.0
8.0
10.
12.
14.
16.
18.
20.
22.
24.
26.
28.
30.
Time (yr)
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1

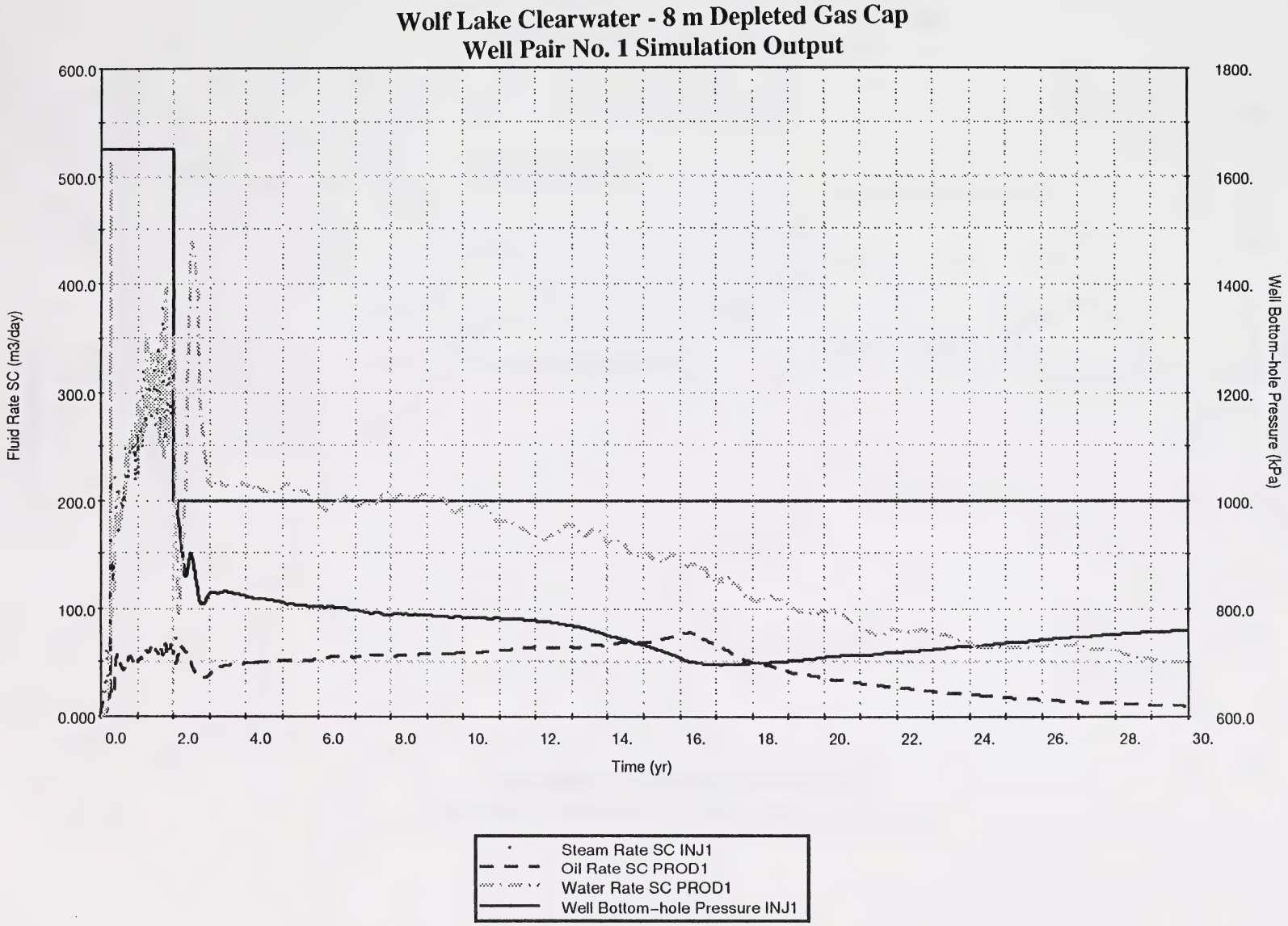

Wolf Lake Clearwater - 4 m Depleted Gas Cap
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
1800.
1600.
1400.
1200.
1000.
800.0
600.0
0.0
2.0
4.0
6.0
8.0
10.
12.
14.
16.
18.
20.
22.
24.
26.
28.
30.
Time (yr)
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2

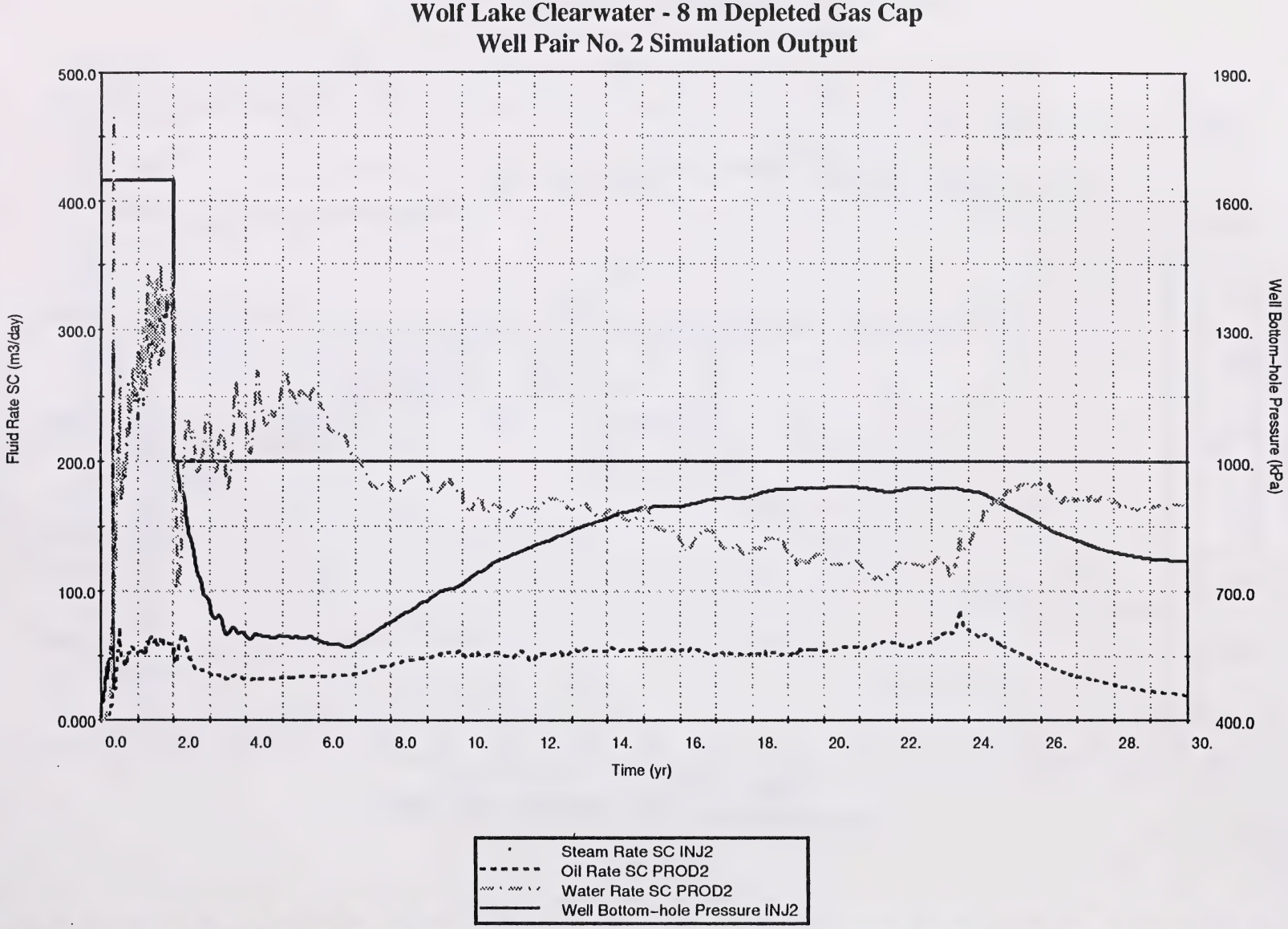

Wolf Lake Clearwater - 4 m Depleted Gas Cap
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
Well Bottom-hole Pressure (kPa)
Time (yr)
500.0
400.0
300.0
200.0
100.0
0.000
1800.
1600.
1400.
1200.
1000.
800.0
600.0
0.0
2.0
4.0
6.0
8.0
10.
12.
14.
16.
18.
20.
22.
24.
26.
28.
30.
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3

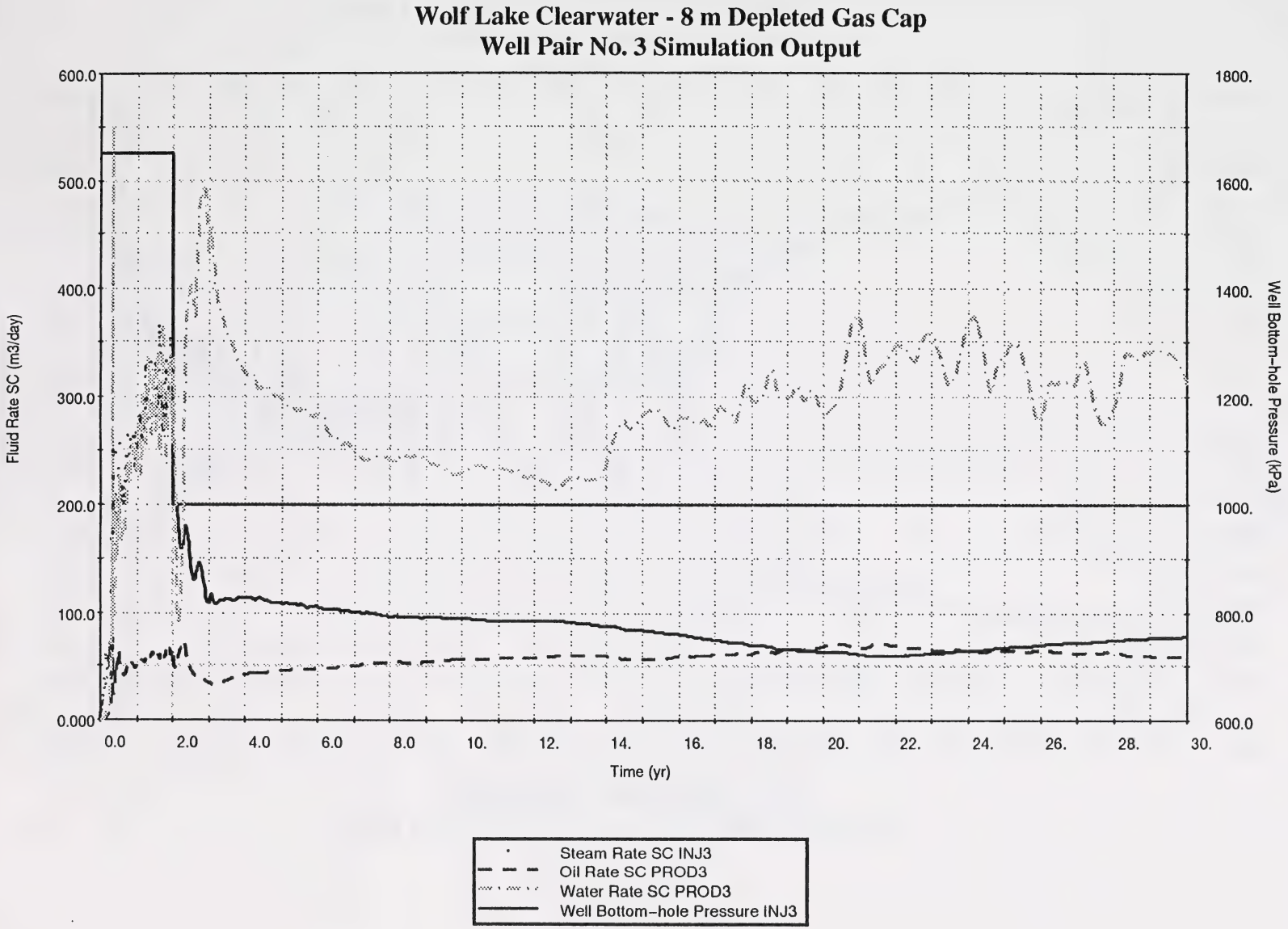

Wolf Lake Clearwater - 4 m Non-depleted Gas Cap
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
Well Bottom-hole Pressure (kPa)
Time (day)
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
2600.
2500.
2400.
2300.
2200.
2100.
2000.
1900.
1800.
1700.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1

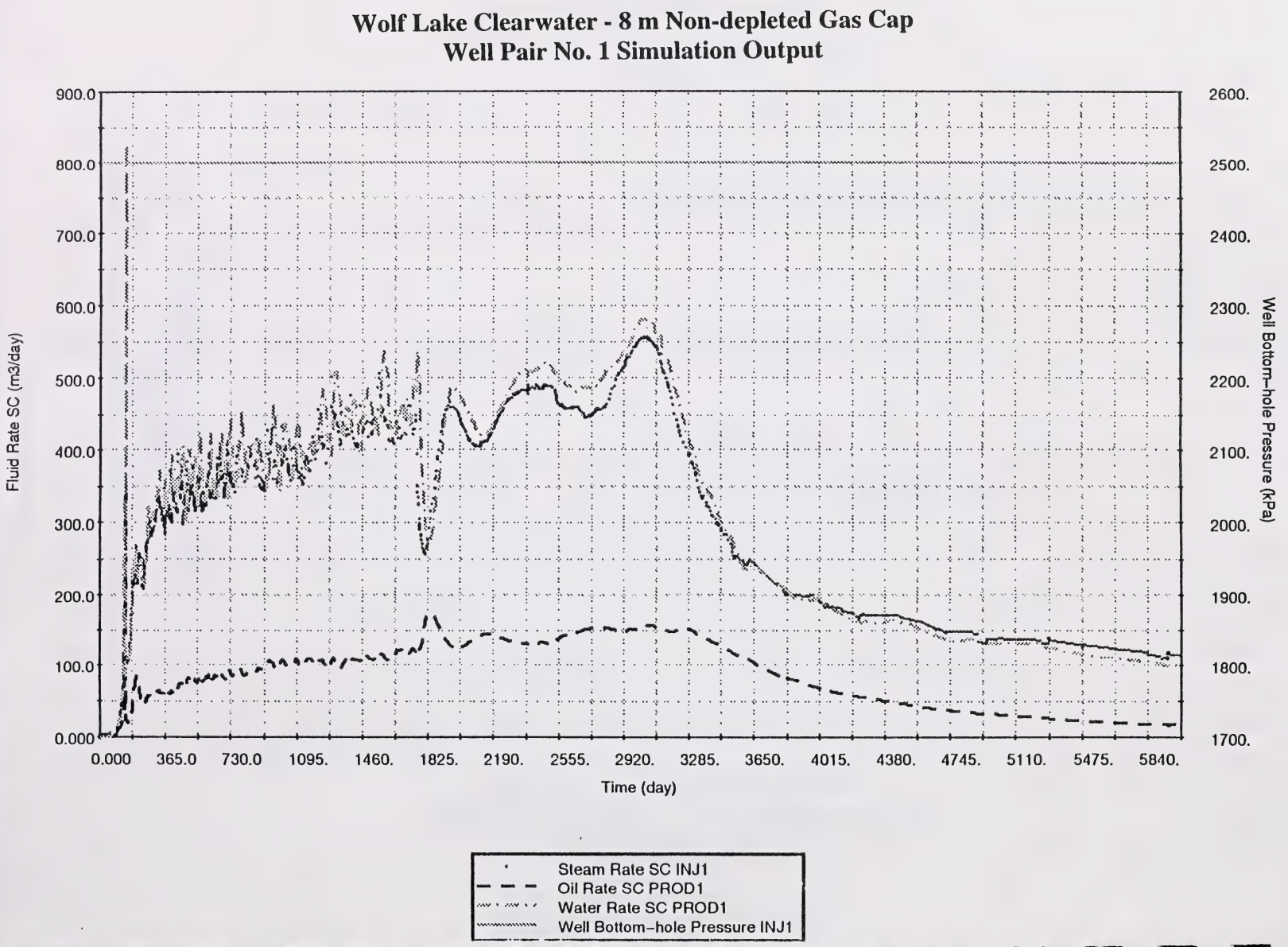

Wolf Lake Clearwater - 4 m Non-depleted Gas Cap
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
2600.
2500.
2400.
2300.
2200.
2100.
2000.
1900.
1800.
1700.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2

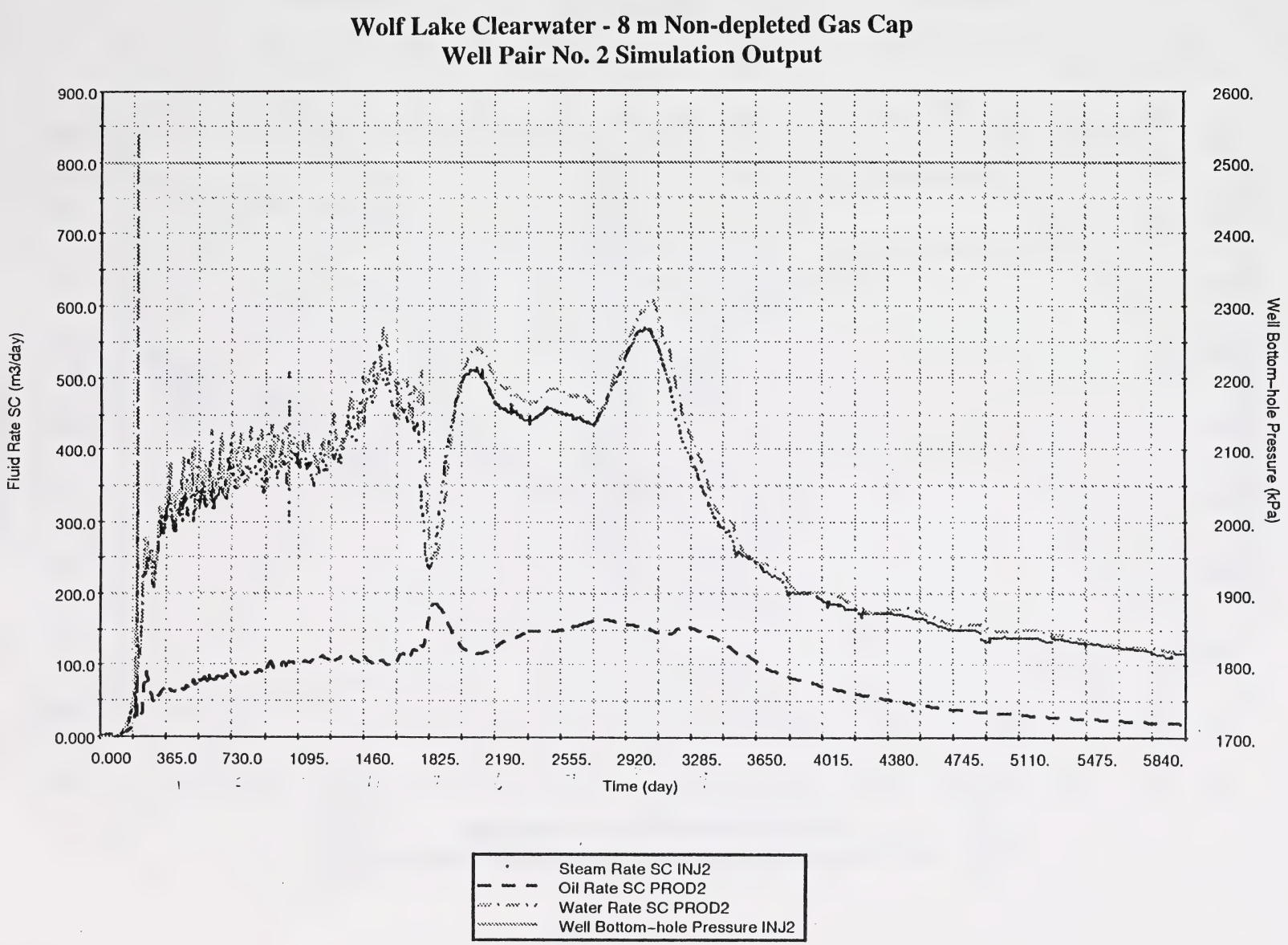

Wolf Lake Clearwater - 4 m Non-depleted Gas Cap
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
2600.
2500.
2400.
2300.
2200.
2100.
2000.
1900.
1800.
1700.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3


Wolf Lake Clearwater - 8 m Depleted Gas Cap
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
1800.
1600.
1400.
1200.
1000.
800.0
600.0
0.0
2.0
4.0
6.0
8.0
10.
12.
14.
16.
18.
20.
22.
24.
26.
28.
30.
Time (yr)
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1

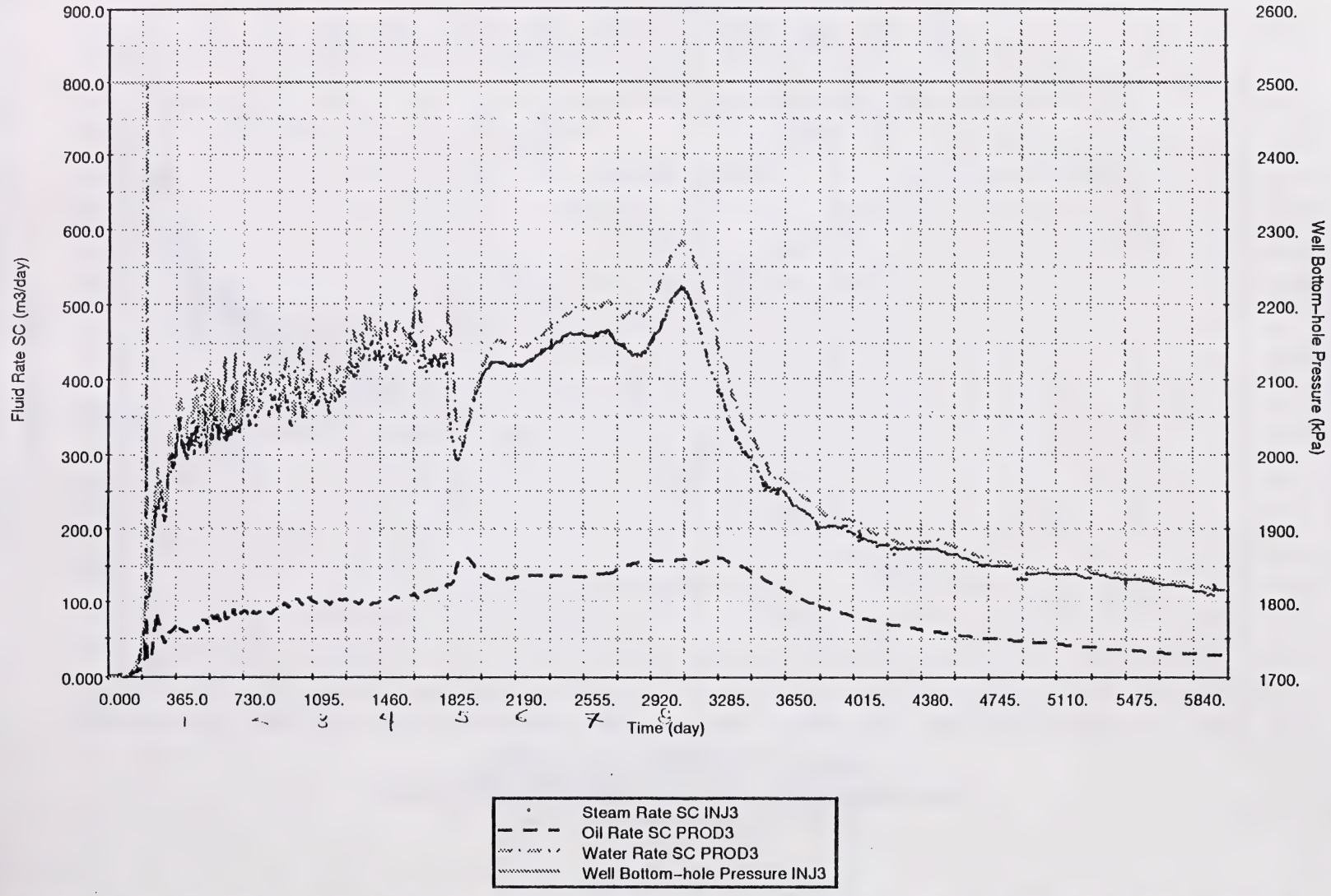

Wolf Lake Clearwater - 8 m Depleted Gas Cap
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
1900.
1600.
1300.
1000.
700.0
400.0
0.0
2.0
4.0
6.0
8.0
10.
12.
14.
16.
18.
20.
22.
24.
26.
28.
30.
Time (yr)
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2


Wolf Lake Clearwater - 8 m Depleted Gas Cap
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
1800.
1600.
1400.
1200.
1000.
800.0
600.0
0.0
2.0
4.0
6.0
8.0
10.
12.
14.
16.
18.
20.
22.
24.
26.
28.
30.
Time (yr)
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3

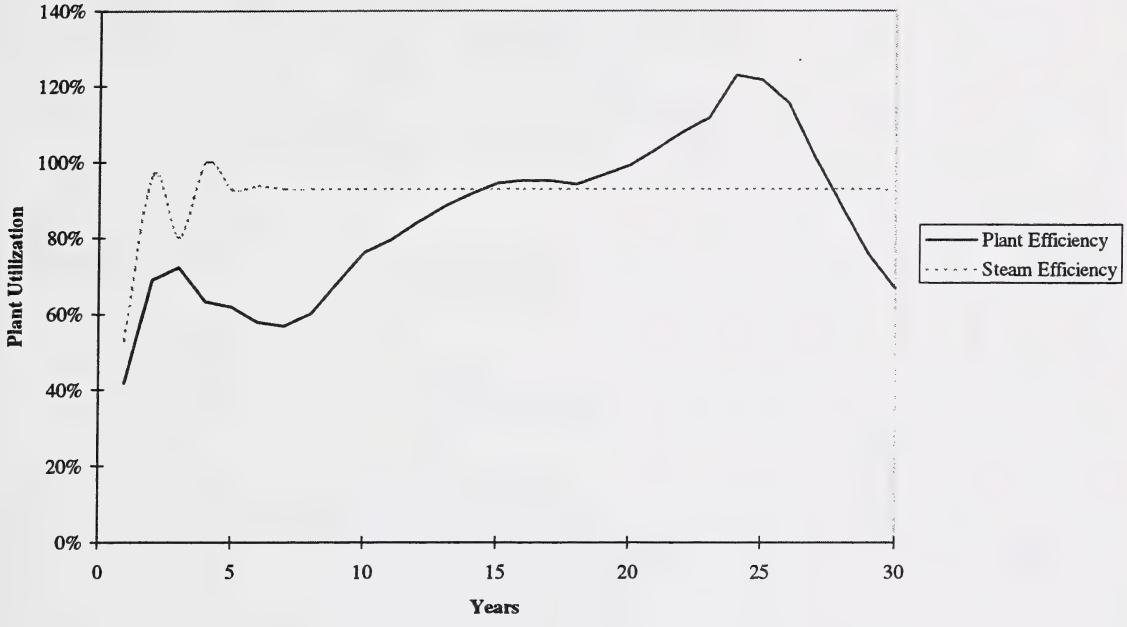

Wolf Lake Clearwater - 8 m Non-depleted Gas Cap
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
2600.
2500.
2400.
2300.
2200.
2100.
2000.
1900.
1800.
1700.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1


Wolf Lake Clearwater - 8 m Non-depleted Gas Cap
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
2600.
2500.
2400.
2300.
2200.
2100.
2000.
1900.
1800.
1700.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2

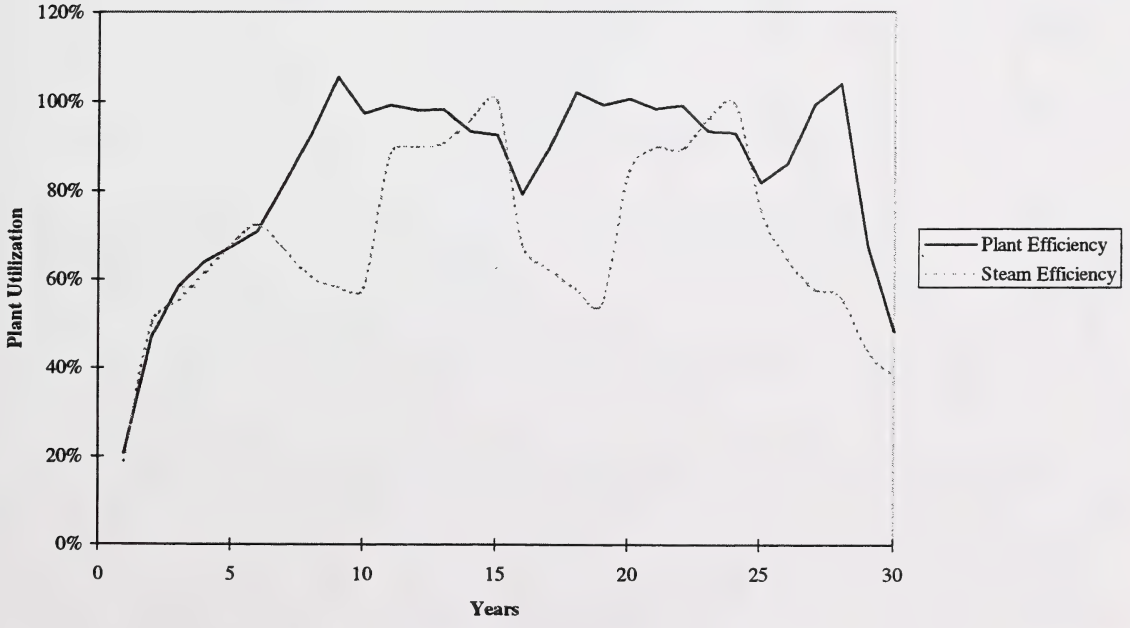
Wolf Lake Clearwater - 8 m Non-depleted Gas Cap
Well Pair No. 3 Simulation Output



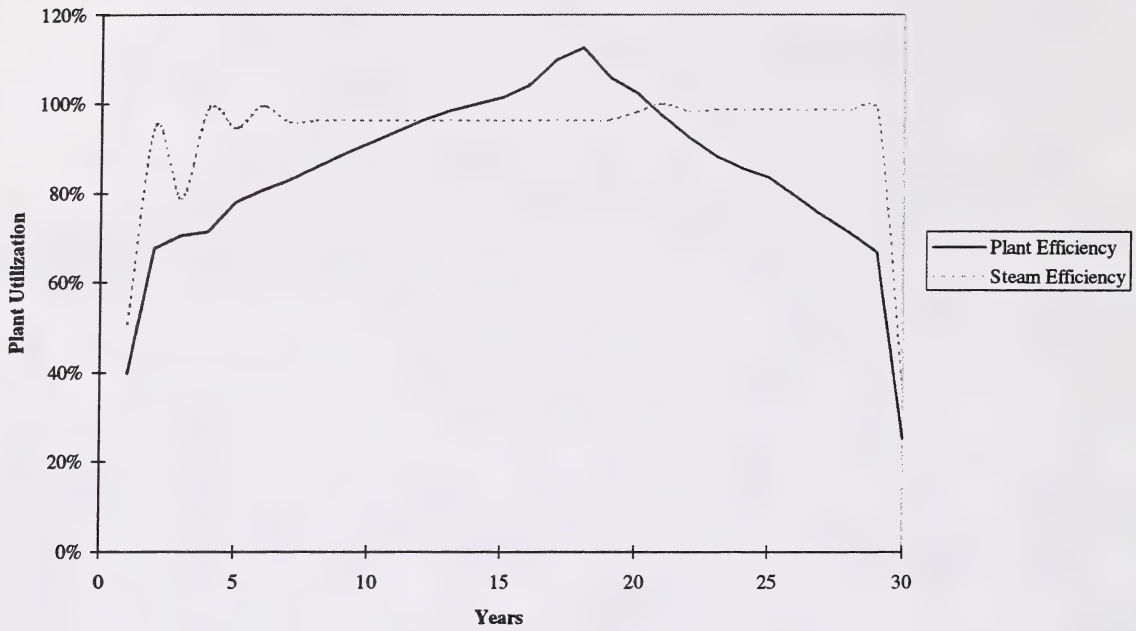
Plant Utilization of Bitumen and Steam Capacity
Wolf Lake Clearwater - 0 m Depleted Gas Cap



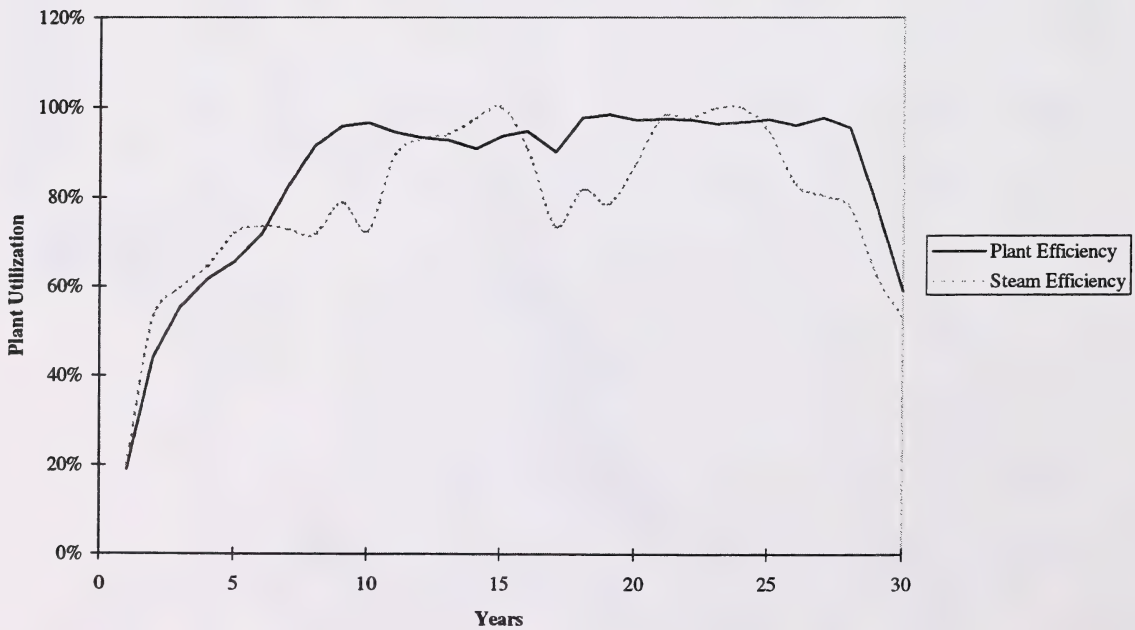
Plant Utilization of Bitumen and Steam Capacity
Wolf Lake Clearwater - 0 m Non-depleted Gas Cap



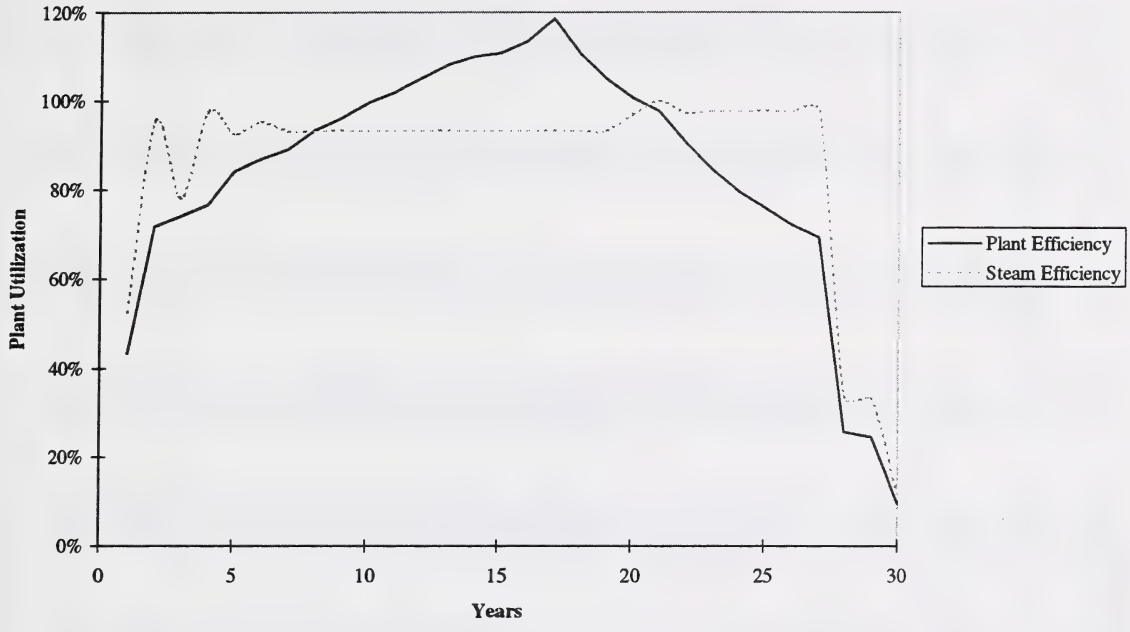
Plant Utilization of Bitumen and Steam Capacity
Wolf Lake Clearwater - 4 m Depleted Gas Cap



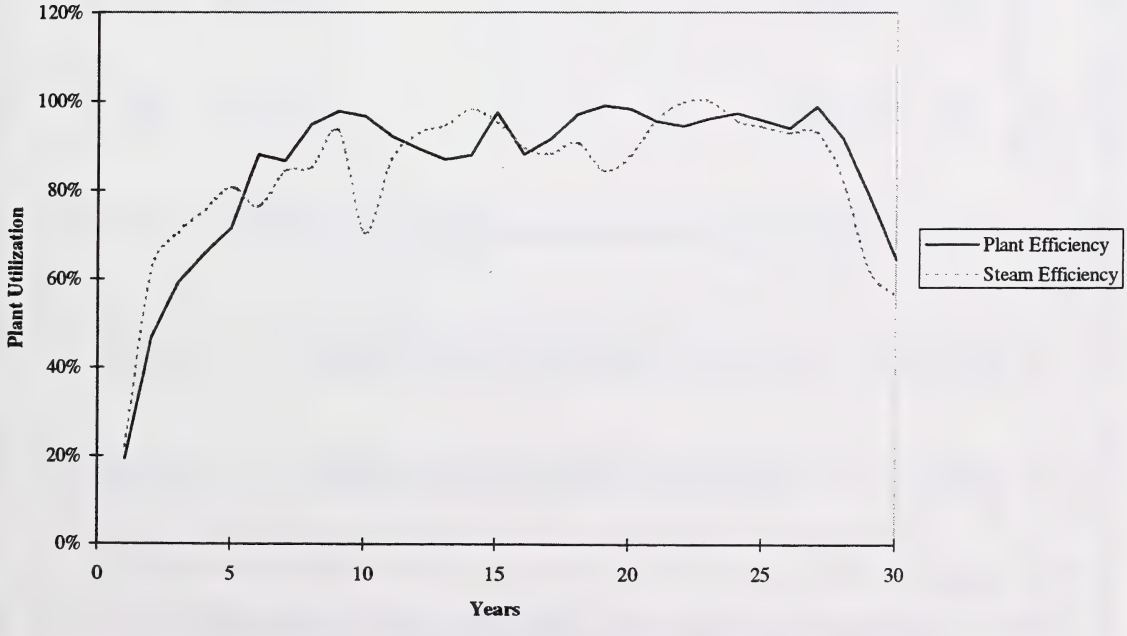
Plant Utilization of Bitumen and Steam Capacity
Wolf Lake Clearwater - 4 m Non-depleted Gas Cap



Plant Utilization of Bitumen and Steam Capacity
Wolf Lake Clearwater - 8 m Depleted Gas Cap



Plant Utilization of Bitumen and Steam Capacity
Wolf Lake Clearwater - 8 m Non-depleted Gas Cap



Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Wolf Lake Clearwater — 0 m Depleted Gas Cap

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$104	$235	$339						
1997	19			$36,100	$141	$319	$36,560						
1998	19			$36,100	$34,525	$78,072	$148,697						
1999	18			$34,200	$35,414	$80,082	$149,696						
2000	9	1,993	9,330	$17,100	$9,416	$21,293	$47,810	$19,088	$5,142	$673	$1,397	$10,850	$37,149
2001	11	3,292	17,020	$20,900			$20,900	$34,821	$9,380	$984	$2,873	$10,850	$58,908
2002	4	3,455	14,100	$7,600			$7,600	$28,847	$7,771	$1,023	$2,523	$10,850	$51,014
2003	0	3,024	17,577	$0			$0	$35,962	$9,688	$919	$3,303	$10,850	$60,723
2004	0	2,958	16,312	$0			$0	$33,372	$8,990	$904	$3,038	$10,850	$57,154
2005	0	2,766	16,483	$0			$0	$33,724	$9,085	$858	$3,082	$10,850	$57,598
2006	0	2,716	16,335	$0			$0	$33,421	$9,003	$846	$3,023	$10,850	$57,144
2007	0	2,869	16,329	$0			$0	$33,408	$9,000	$882	$2,940	$10,850	$57,080
2008	0	3,261	16,358	$0			$0	$33,467	$9,016	$976	$2,874	$10,850	$57,183
2009	0	3,635	16,329	$0			$0	$33,408	$9,000	$1,066	$2,856	$10,850	$57,179
2010	0	3,791	16,335	$0			$0	$33,421	$9,003	$1,103	$2,819	$10,850	$57,197
2011	0	4,013	16,329	$0			$0	$33,408	$9,000	$1,156	$2,833	$10,850	$57,247
2012	0	4,210	16,358	$0			$0	$33,467	$9,016	$1,203	$2,863	$10,850	$57,399
2013	0	4,375	16,329	$0			$0	$33,408	$9,000	$1,243	$2,869	$10,850	$57,370
2014	0	4,508	16,335	$0			$0	$33,421	$9,003	$1,275	$2,893	$10,850	$57,443
2015	0	4,541	16,329	$0			$0	$33,408	$9,000	$1,283	$2,912	$10,850	$57,452
2016	0	4,544	16,358	$0			$0	$33,467	$9,016	$1,284	$2,885	$10,850	$57,502
2017	0	4,492	16,329	$0			$0	$33,408	$9,000	$1,271	$2,915	$10,850	$57,444
2018	0	4,612	16,335	$0			$0	$33,421	$9,003	$1,300	$2,847	$10,850	$57,421
2019	0	4,728	16,329	$0			$0	$33,408	$9,000	$1,328	$2,926	$10,850	$57,511
2020	0	4,931	16,358	$0			$0	$33,467	$9,016	$1,376	$2,849	$10,850	$57,558
2021	0	5,148	16,329	$0			$0	$33,408	$9,000	$1,428	$2,940	$10,850	$57,626
2022	0	5,327	16,335	$0			$0	$33,421	$9,003	$1,471	$2,854	$10,850	$57,600
2023	0	5,868	16,329	$0			$0	$33,408	$9,000	$1,601	$2,958	$10,850	$57,816
2024	0	5,804	16,358	$0			$0	$33,467	$9,016	$1,585	$3,047	$10,850	$57,965
2025	0	5,520	16,329	$0			$0	$33,408	$9,000	$1,517	$2,996	$10,850	$57,771
2026	0	4,821	16,335	$0			$0	$33,421	$9,003	$1,350	$2,988	$10,850	$57,612
2027	0	4,220	16,329	$0			$0	$33,408	$9,000	$1,206	$2,956	$10,850	$57,419
2028	0	3,616	16,358	$0			$0	$33,467	$9,016	$1,061	$2,840	$10,850	$57,234
2029	0	3,187	16,266	$0			$0	$33,279	$8,965	$959	$2,799	$14,850	$60,852
Totals	80	44,611,910	176,245,317	$152,000	$79,601	$180,000	$411,601	$987,908	$266,130	$35,131	$85,897	$329,500	$1,704,566

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Wolf Lake Clearwater — 0 m Non-depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$123	$235	$358						
1997	10			$19,000	$167	$319	$19,486						
1998	10			$19,000	$40,994	$78,072	$138,066						
1999	10			$19,000	$42,050	$80,082	$141,131						
2000	9	982	3,919	$17,100	$11,181	$21,293	$49,574	$8,018	$2,160	$430	$683	$10,850	$22,141
2001	9	2,242	10,457	$17,100			$17,100	$21,395	$5,764	$732	$1,857	$10,850	$40,598
2002	9	2,778	11,518	$17,100			$17,100	$23,565	$6,348	$861	$2,007	$10,850	$43,631
2003	9	3,059	12,841	$17,100			$17,100	$26,271	$7,077	$928	$2,228	$10,850	$47,355
2004	9	3,217	14,147	$17,100			$17,100	$28,943	$7,797	$966	$2,461	$10,850	$51,017
2005	9	3,380	15,091	$17,100			$17,100	$30,874	$8,317	$1,005	$2,647	$10,850	$53,693
2006	6	3,892	13,912	$11,400			$11,400	$28,463	$7,667	$1,127	$2,470	$10,850	$50,577
2007	0	4,421	12,628	$0			$0	$25,836	$6,960	$1,254	$2,287	$10,850	$47,187
2008	0	5,030	12,158	$0			$0	$24,874	$6,701	$1,400	$2,233	$10,850	$46,057
2009	0	4,640	12,082	$0			$0	$24,719	$6,659	$1,307	$2,151	$10,850	$45,686
2010	0	4,732	18,413	$0			$0	$37,672	$10,148	$1,329	$3,245	$10,850	$63,244
2011	0	4,681	18,725	$0			$0	$38,311	$10,320	$1,316	$3,264	$10,850	$64,061
2012	0	4,686	18,911	$0			$0	$38,691	$10,423	$1,318	$3,277	$10,850	$64,559
2013	0	4,445	20,033	$0			$0	$40,986	$11,041	$1,260	$3,482	$10,850	$67,619
2014	0	4,410	20,871	$0			$0	$42,701	$11,503	$1,252	$3,620	$10,850	$69,925
2015	0	3,771	14,134	$0			$0	$28,917	$7,790	$1,098	$2,513	$10,850	$51,168
2016	0	4,256	13,048	$0			$0	$26,695	$7,191	$1,215	$2,351	$10,850	$48,301
2017	0	4,866	12,081	$0			$0	$24,718	$6,659	$1,361	$2,203	$10,850	$45,791
2018	0	4,733	11,354	$0			$0	$23,229	$6,257	$1,329	$2,067	$10,850	$43,732
2019	0	4,796	17,604	$0			$0	$36,017	$9,703	$1,344	$3,086	$10,850	$61,000
2020	0	4,691	18,690	$0			$0	$38,238	$10,301	$1,319	$3,263	$10,850	$63,970
2021	0	4,725	18,599	$0			$0	$38,051	$10,251	$1,327	$3,236	$10,850	$63,715
2022	0	4,452	20,039	$0			$0	$40,999	$11,045	$1,262	$3,486	$10,850	$67,641
2023	0	4,431	20,728	$0			$0	$42,407	$11,424	$1,257	$3,575	$10,850	$69,513
2024	0	3,896	15,778	$0			$0	$32,280	$8,696	$1,128	$2,793	$10,850	$55,748
2025	0	4,099	13,475	$0			$0	$27,569	$7,427	$1,177	$2,416	$10,850	$49,439
2026	0	4,738	12,080	$0			$0	$24,714	$6,658	$1,330	$2,201	$10,850	$45,753
2027	0	4,954	11,694	$0			$0	$23,925	$6,445	$1,382	$2,138	$10,850	$44,740
2028	0	3,224	92,08	$0			$0	$18,839	$5,075	$967	$1,620	$10,850	$37,351
2029	0	2,299	7,916	$0			$0	$16,195	$4,363	$746	$1,371	$15,350	$38,024
Totals	90	43,993,351	157,727,756	$171,000	$94,516	$180,000	$445,516	$884,112	$238,169	$34,725	$76,230	$330,000	$1,563,235

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Wolf Lake Clearwater — 4 m Depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$103	$235	$337						
1997	18			$34,200	$139	$319	$34,658						
1998	18			$34,200	$34,121	$78,072	$146,393						
1999	18			$34,200	$35,000	$80,082	$149,282						
2000	9	1,904	8,840	$17,100	$9,306	$21,293	$47,700	$18,086	$4,872	$651	$1,324	$10,850	$35,783
2001	11	3,234	16,496	$20,900			$20,900	$33,751	$9,092	$970	$2,771	$10,850	$57,433
2002	9	3,373	13,700	$17,100			$17,100	$28,029	$7,551	$1,003	$3,288	$10,850	$50,721
2003	1	3,407	17,215	$1,900			$1,900	$35,220	$9,488	$1,011	$3,651	$10,850	$60,220
2004	0	3,724	16,439	$0			$0	$33,633	$9,060	$1,087	$3,595	$10,850	$58,226
2005	0	3,854	17,291	$0			$0	$35,376	$9,530	$1,118	$3,563	$10,850	$60,437
2006	0	3,959	16,652	$0			$0	$34,068	$9,178	$1,144	$3,367	$10,850	$58,607
2007	0	4,091	16,736	$0			$0	$34,240	$9,224	$1,175	$3,204	$10,850	$58,694
2008	0	4,230	16,768	$0			$0	$34,307	$9,242	$1,208	$3,099	$10,850	$58,706
2009	0	4,352	16,736	$0			$0	$34,240	$9,224	$1,238	$3,054	$10,850	$58,606
2010	0	4,480	16,745	$0			$0	$34,259	$9,229	$1,268	$3,016	$10,850	$58,622
2011	0	4,597	16,736	$0			$0	$34,240	$9,224	$1,296	$2,961	$10,850	$58,571
2012	0	4,700	16,768	$0			$0	$34,307	$9,242	$1,321	$2,993	$10,850	$58,712
2013	0	4,776	16,736	$0			$0	$34,242	$9,224	$1,339	$2,999	$10,850	$58,654
2014	0	4,842	16,745	$0			$0	$34,259	$9,229	$1,355	$3,007	$10,850	$58,700
2015	0	4,962	16,736	$0			$0	$34,241	$9,224	$1,384	$2,990	$10,850	$58,689
2016	0	5,241	16,768	$0			$0	$34,307	$9,242	$1,451	$2,945	$10,850	$58,794
2017	0	5,377	16,736	$0			$0	$34,241	$9,224	$1,483	$2,853	$10,850	$58,650
2018	0	5,054	16,745	$0			$0	$34,259	$9,229	$1,406	$2,936	$10,850	$58,679
2019	0	4,890	17,063	$0			$0	$34,910	$9,404	$1,367	$2,833	$10,850	$59,364
2020	0	4,648	17,372	$0			$0	$35,542	$9,574	$1,308	$2,906	$10,850	$60,180
2021	0	4,412	17,113	$0			$0	$35,012	$9,432	$1,252	$2,821	$10,850	$59,366
2022	0	4,214	17,153	$0			$0	$35,094	$9,454	$1,205	$2,752	$10,850	$59,354
2023	0	4,079	17,145	$0			$0	$35,078	$9,450	$1,172	$2,701	$10,850	$59,251
2024	0	3,983	17,176	$0			$0	$35,142	$9,467	$1,149	$2,495	$10,850	$59,102
2025	0	3,793	17,144	$0			$0	$35,075	$9,449	$1,104	$2,432	$10,850	$58,910
2026	0	3,575	17,153	$0			$0	$35,094	$9,454	$1,051	$2,325	$10,850	$58,774
2027	0	3,398	17,145	$0			$0	$35,078	$9,450	$1,009	$2,246	$10,850	$58,632
2028	0	3,193	17,176	$0			$0	$35,142	$9,467	$960	$2,200	$10,850	$58,618
2029	0	1,208	6,124	$0			$0	$12,528	$3,375	$484	$803	$15,050	$32,241
Totals	84	44,365,321	177,153,311	$159,600	$78,670	$180,000	$418,270	$992,998	$267,501	$34,969	$84,130	$329,700	$1,709,298

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Wolf Lake Clearwater — 4 m Non-depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$107	$235	$342						
1997	10			$19,000	$146	$319	$19,464						
1998	10			$19,000	$35,667	$78,072	$132,739						
1999	8			$15,200	$36,586	$80,082	$131,867						
2000	9	910	3,615	$17,100	$9,728	$21,293	$48,121	$7,396	$1,992	$413	$635	$10,850	$21,287
2001	9	2,103	9,705	$17,100			$17,100	$19,855	$5,349	$699	$1,735	$10,850	$38,487
2002	9	2,634	10,825	$17,100			$17,100	$22,147	$5,966	$826	$1,898	$10,850	$41,688
2003	9	2,940	11,696	$17,100			$17,100	$23,929	$6,446	$899	$2,052	$10,850	$44,177
2004	9	3,126	13,046	$17,100			$17,100	$26,692	$7,190	$944	$2,293	$10,850	$47,970
2005	9	3,422	13,351	$17,100			$17,100	$27,314	$7,358	$1,015	$2,355	$10,850	$48,893
2006	9	3,929	13,216	$17,100			$17,100	$27,040	$7,284	$1,136	$2,358	$10,850	$48,669
2007	1	4,358	13,003	$1,900			$1,900	$26,604	$7,167	$1,239	$2,350	$10,850	$48,209
2008	0	4,574	14,318	$0			$0	$29,293	$7,891	$1,291	$2,593	$10,850	$51,918
2009	0	4,605	13,152	$0			$0	$26,908	$7,249	$1,298	$2,377	$10,850	$48,682
2010	0	4,507	16,252	$0			$0	$33,250	$8,957	$1,275	$2,873	$10,850	$57,205
2011	0	4,453	16,903	$0			$0	$34,583	$9,316	$1,262	$2,971	$10,850	$58,981
2012	0	4,423	17,070	$0			$0	$34,924	$9,408	$1,255	$2,995	$10,850	$59,431
2013	0	4,334	17,716	$0			$0	$36,247	$9,764	$1,233	$3,099	$10,850	$61,194
2014	0	4,470	18,159	$0			$0	$37,152	$10,008	$1,266	$3,204	$10,850	$62,479
2015	0	4,521	16,484	$0			$0	$33,726	$9,085	$1,278	$2,918	$10,850	$57,857
2016	0	4,294	13,340	$0			$0	$27,293	$7,352	$1,224	$2,397	$10,850	$49,116
2017	0	4,658	14,839	$0			$0	$30,361	$8,179	$1,311	$2,678	$10,850	$53,379
2018	0	4,695	14,240	$0			$0	$29,134	$7,848	$1,320	$2,573	$10,850	$51,725
2019	0	4,636	15,887	$0			$0	$32,503	$8,756	$1,306	$2,808	$10,850	$56,223
2020	0	4,649	17,764	$0			$0	$36,344	$9,791	$1,309	$3,131	$10,850	$61,425
2021	0	4,644	17,739	$0			$0	$36,293	$9,777	$1,308	$3,118	$10,850	$61,345
2022	0	4,597	18,114	$0			$0	$37,060	$9,984	$1,296	$3,175	$10,850	$62,365
2023	0	4,610	18,131	$0			$0	$37,095	$9,993	$1,299	$3,198	$10,850	$62,435
2024	0	4,644	17,155	$0			$0	$35,098	$9,455	$1,307	$3,038	$10,850	$59,749
2025	0	4,581	15,032	$0			$0	$30,754	$8,285	$1,292	$2,693	$10,850	$53,875
2026	0	4,657	14,591	$0			$0	$29,853	$8,042	$1,311	$2,623	$10,850	$52,678
2027	0	4,553	14,119	$0			$0	$28,886	$7,781	$1,286	$2,546	$10,850	$51,349
2028	0	3,713	11,357	$0			$0	$23,235	$6,259	$1,085	$2,018	$10,850	$43,447
2029	0	2,820	9,605	$0			$0	$19,652	$5,294	$871	$1,684	$15,450	$42,950
Totals	92	44,187,044	157,104,992	$174,800	$82,234	$180,000	$437,034	$880,621	$237,229	$34,852	$76,385	$330,100	$1,559,186

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Wolf Lake Clearwater — 8 m Depleted Gas Cap

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$109	$235	$343						
1997	20			$38,000	$147	$319	$38,466						
1998	20			$38,000	$36,119	$78,072	$152,191						
1999	18			$34,200	$37,049	$80,082	$151,331						
2000	9	2,071	9,673	$17,100	$9,851	$21,293	$48,245	$19,791	$5,332	$691	$1,452	$10,850	$38,116
2001	11	3,425	17,565	$20,900			$20,900	$35,937	$9,681	$1,015	$2,959	$10,850	$60,442
2002	9	3,537	14,369	$17,100			$17,100	$29,399	$7,920	$1,042	$3,516	$10,850	$52,727
2003	1	3,660	17,956	$1,900			$1,900	$36,736	$9,896	$1,072	$3,768	$10,850	$62,322
2004	0	4,020	17,017	$0			$0	$34,816	$9,379	$1,158	$3,762	$10,850	$59,964
2005	0	4,150	17,532	$0			$0	$35,869	$9,663	$1,189	$3,602	$10,850	$61,172
2006	0	4,250	17,154	$0			$0	$35,096	$9,454	$1,213	$3,475	$10,850	$60,089
2007	0	4,452	17,146	$0			$0	$35,080	$9,450	$1,261	$3,273	$10,850	$59,914
2008	0	4,589	17,175	$0			$0	$35,140	$9,466	$1,294	$3,190	$10,850	$59,940
2009	0	4,750	17,143	$0			$0	$35,073	$9,448	$1,333	$3,119	$10,850	$59,823
2010	0	4,868	17,154	$0			$0	$35,096	$9,454	$1,361	$3,087	$10,850	$59,849
2011	0	5,020	17,146	$0			$0	$35,080	$9,450	$1,398	$2,977	$10,850	$59,755
2012	0	5,164	17,175	$0			$0	$35,140	$9,466	$1,432	$2,895	$10,850	$59,782
2013	0	5,253	17,144	$0			$0	$35,075	$9,449	$1,453	$2,911	$10,850	$59,738
2014	0	5,284	17,154	$0			$0	$35,096	$9,454	$1,461	$2,994	$10,850	$59,855
2015	0	5,414	17,146	$0			$0	$35,081	$9,450	$1,492	$3,010	$10,850	$59,883
2016	0	5,659	17,175	$0			$0	$35,140	$9,466	$1,551	$2,978	$10,850	$59,984
2017	0	5,283	17,143	$0			$0	$35,073	$9,448	$1,461	$2,943	$10,850	$59,775
2018	0	5,007	17,154	$0			$0	$35,096	$9,454	$1,394	$2,891	$10,850	$59,686
2019	0	4,803	17,822	$0			$0	$36,463	$9,823	$1,346	$2,874	$10,850	$61,356
2020	0	4,662	18,389	$0			$0	$37,623	$10,135	$1,312	$3,014	$10,850	$62,933
2021	0	4,324	17,897	$0			$0	$36,616	$9,864	$1,231	$2,919	$10,850	$61,479
2022	0	4,033	17,970	$0			$0	$36,766	$9,904	$1,161	$2,959	$10,850	$61,641
2023	0	3,796	17,965	$0			$0	$36,755	$9,901	$1,104	$2,829	$10,850	$61,440
2024	0	3,623	17,991	$0			$0	$36,809	$9,916	$1,063	$2,832	$10,850	$61,470
2025	0	3,446	17,959	$0			$0	$36,744	$9,898	$1,021	$2,693	$10,850	$61,206
2026	0	3,312	17,970	$0			$0	$36,766	$9,904	$988	$2,636	$10,850	$61,145
2027	0	1,222	6,231	$0			$0	$12,748	$3,434	$488	$944	$10,850	$28,465
2028	0	1,171	6,122	$0			$0	$12,526	$3,374	$476	$905	$10,850	$28,131
2029	0	457	2,041	$0			$0	$4,176	$1,125	$305	$318	$15,250	$21,173
Totals	88	44,056,989	173,550,598	$167,200	$83,276	$180,000	$430,476	$972,803	$262,061	$34,767	$83,723	$329,900	$1,683,255

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Wolf Lake Clearwater — 8 m Non-depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$97	$235	$332						
1997	10			$19,000	$132	$319	$19,451						
1998	10			$19,000	$32,321	$78,072	$129,393						
1999	10			$19,000	$33,153	$80,082	$132,235						
2000	9	928	3,624	$17,100	$8,815	$21,293	$47,209	$7,414	$1,997	$417	$637	$10,850	$21,316
2001	9	2,235	10,337	$17,100			$17,100	$21,150	$5,698	$730	$1,849	$10,850	$40,277
2002	9	2,813	11,586	$17,100			$17,100	$23,705	$6,386	$869	$2,036	$10,850	$43,845
2003	9	3,149	12,441	$17,100			$17,100	$25,453	$6,857	$949	$2,181	$10,850	$46,291
2004	9	3,413	13,273	$17,100			$17,100	$27,157	$7,316	$1,013	$2,406	$10,850	$48,741
2005	9	4,199	12,558	$17,100			$17,100	$25,692	$6,921	$1,201	$2,193	$10,850	$46,857
2006	9	4,134	13,870	$17,100			$17,100	$28,377	$7,644	$1,185	$2,461	$10,850	$50,518
2007	1	4,526	14,016	$1,900			$1,900	$28,676	$7,725	$1,279	$2,520	$10,850	$51,050
2008	0	4,668	15,363	$0			$0	$31,432	$8,467	$1,313	$2,812	$10,850	$54,874
2009	0	4,611	11,562	$0			$0	$23,654	$6,372	$1,300	$2,086	$10,850	$44,262
2010	0	4,403	14,310	$0			$0	$29,278	$7,887	$1,250	$2,534	$10,850	$51,799
2011	0	4,270	15,283	$0			$0	$31,268	$8,423	$1,218	$2,685	$10,850	$54,444
2012	0	4,151	15,578	$0			$0	$31,872	$8,586	$1,189	$2,734	$10,850	$55,231
2013	0	4,196	16,174	$0			$0	$33,091	$8,914	$1,200	$2,868	$10,850	$56,924
2014	0	4,654	15,708	$0			$0	$32,138	$8,658	$1,310	$2,769	$10,850	$55,724
2015	0	4,199	14,737	$0			$0	$30,151	$8,122	$1,201	$2,601	$10,850	$52,925
2016	0	4,374	14,532	$0			$0	$29,731	$8,009	$1,243	$2,601	$10,850	$52,434
2017	0	4,631	14,933	$0			$0	$30,552	$8,230	$1,304	$2,705	$10,850	$53,641
2018	0	4,722	13,889	$0			$0	$28,416	$7,655	$1,326	$2,508	$10,850	$50,755
2019	0	4,690	14,448	$0			$0	$29,560	$7,963	$1,319	$2,568	$10,850	$52,259
2020	0	4,558	15,806	$0			$0	$32,339	$8,712	$1,287	$2,788	$10,850	$55,976
2021	0	4,505	16,422	$0			$0	$33,598	$9,051	$1,274	$2,889	$10,850	$57,662
2022	0	4,588	16,455	$0			$0	$33,667	$9,069	$1,294	$2,914	$10,850	$57,794
2023	0	4,640	15,744	$0			$0	$32,211	$8,677	$1,307	$2,801	$10,850	$55,845
2024	0	4,570	15,523	$0			$0	$31,759	$8,556	$1,290	$2,740	$10,850	$55,194
2025	0	4,487	15,293	$0			$0	$31,288	$8,429	$1,270	$2,732	$10,850	$54,568
2026	0	4,716	15,307	$0			$0	$31,317	$8,436	$1,325	$2,750	$10,850	$54,678
2027	0	4,381	13,521	$0			$0	$27,663	$7,452	$1,244	$2,428	$10,850	$49,637
2028	0	3,739	10,186	$0			$0	$20,840	$5,614	$1,091	$1,826	$10,850	$40,220
2029	0	3,081	9,290	$0			$0	$19,007	$5,120	$933	$1,634	$15,550	$42,244
Totals	94	44,613,359	150,295,798	$178,600	$74,519	$180,000	$433,119	$842,453	$226,947	$35,132	$73,255	$330,200	$1,507,986

Appendix F

Gas Cap Effect Simulation Data Set and Results, Commercial Plant Utilization and Detailed Plant Bitumen Forecasts and Undiscounted Costs for Clearwater Burnt Lake

```
**  SOURCE DATA SET: BURNT LAKE CLEARWATER CASE STUDY - BASE CASE
**  CMG STARS SIMULATION
**
**  No Gas Cap (Base Case Run)
**  2D Run assuming a Live Oil (14 mol % Solution Gas)
**  Model Dimensions: 549 m x 1000 m x 34 m
**  1000 m Horizontal Wells and 26 m of Pay above Producer Wells
**  Initial Reservoir Pressure = 3100 kPa
**  Full Scale Pattern Simulation with 3 Well Pairs
** (Well Pair 1 assumes perfect symmetry)
** Inter-Well Distance is 90 m and Injector/Producer Vertical Spacing is 6 m
** Grid Block thickness is variable in i-direction (either 2 m or 5 m blocks),
** j-direction consists of a single slab of 1000 m thickness and k-direction
** consists of a constant 2 m thickness for each block
** Input and Output Units are SI; and time basis is days
**
**  --------------  INPUT/OUTPUT CONTROL  ----------------------

*filename *index-in 'Burnt_Lake_Base_NonDep.irf' *main-results-in


*title1 'Joint ADOE-EUB SAGD Study'
*title2 'Case Study: Burnt Lake Clearwater'
*title3 'Pattern Simulation'

**restart

*maxerror 1
*wrst *time

*prntorien 2 0
*outprn *grid *pres *temp *sw *so *sg *x *y
*outprn *well *brief
*wsrf *grid *time
*outsrf *grid *pres *temp *sw *so *sg *x *y

** ----------------------- GRID AND RESERVOIR DEFINITION -----------------

*grid *cart 180 1 17

*kdir *up

*di *ivar 115*2.0 63*5.0 2*2.0

*dj *con 1000

*dk *kvar 17*2.0

*vamod 2 0.5 1.0 0.5 0.5 *9p 1.0 1.0
*vatype *ivar 2 179*1

*dtop *con 500.0
```

```
*por *ijk
1:180 1 1:3       0.22
1:180 1 4:6       0.30
1:180 1 7:9       0.29
1:180 1 10:11     0.33
1:3   1 12        0.00
4:7   1 12        0.32
8:12  1 12        0.00
13:15 1 12        0.32
16:20 1 12        0.00
21:23 1 12        0.32
24:28 1 12        0.00
29:31 1 12        0.32
32:36 1 12        0.00
37:39 1 12        0.32
40:44 1 12        0.00
45:47 1 12        0.32
48:52 1 12        0.00
53:55 1 12        0.32
56:60 1 12        0.00
61:63 1 12        0.32
64:68 1 12        0.00
69:71 1 12        0.32
72:76 1 12        0.00
77:79 1 12        0.32
80:84 1 12        0.00
85:87 1 12        0.32
88:92 1 12        0.00
93:95 1 12        0.32
96:100 1 12       0.00
101:103 1 12      0.32
104:108 1 12      0.00
109:111 1 12      0.32
112:116 1 12      0.00
117:117 1 12      0.32
118:119 1 12      0.00
120:120 1 12      0.32
121:122 1 12      0.00
123:123 1 12      0.32
124:125 1 12      0.00
126:127 1 12      0.32
128:130 1 12      0.00
131:132 1 12      0.32
133:135 1 12      0.00
136:137 1 12      0.32
138:140 1 12      0.00
141:142 1 12      0.32
143:145 1 12      0.00
146:147 1 12      0.32
148:150 1 12      0.00
151:152 1 12      0.32
153:155 1 12      0.00
156:157 1 12      0.32
158:160 1 12      0.00
161:162 1 12      0.32
163:165 1 12      0.00
166:167 1 12      0.32
168:170 1 12      0.00
```

```
171:172 1 12      0.32
173:175 1 12      0.00
176:177 1 12      0.32
178:180 1 12      0.00
1:180 1 13:17     0.32
```

```
*permi *ijk
1:180 1 1:3       1500
1:180 1 4:6       1700
1:180 1 7:9       3000
1:180 1 10:11     2500
1:3   1 12        0.00
4:7   1 12        2500
8:12  1 12        0.00
13:15 1 12        2500
16:20 1 12        0.00
21:23 1 12        0.32
24:28 1 12        0.00
29:31 1 12        2500
32:36 1 12        0.00
37:39 1 12        2500
40:44 1 12        0.00
45:47 1 12        2500
48:52 1 12        0.00
53:55 1 12        2500
56:60 1 12        0.00
61:63 1 12        2500
64:68 1 12        0.00
69:71 1 12        2500
72:76 1 12        0.00
77:79 1 12        2500
80:84 1 12        0.00
85:87 1 12        2500
88:92 1 12        0.00
93:95 1 12        2500
96:100 1 12       0.00
101:103 1 12      2500
104:108 1 12      0.00
109:111 1 12      2500
112:116 1 12      0.00
117:117 1 12      2500
118:119 1 12      0.00
120:120 1 12      2500
121:122 1 12      0.00
123:123 1 12      2500
124:125 1 12      0.00
126:127 1 12      2500
128:130 1 12      0.00
131:132 1 12      2500
133:135 1 12      0.00
136:137 1 12      2500
138:140 1 12      0.00
141:142 1 12      2500
143:145 1 12      0.00
146:147 1 12      2500
148:150 1 12      0.00
151:152 1 12      2500
153:155 1 12      0.00
156:157 1 12      2500
158:160 1 12      0.00
161:162 1 12      2500
163:165 1 12      0.00
166:167 1 12      2500
168:170 1 12      0.00
```

File: Burnt_Lake_Study.dat 2

```
171:172 1 12      2500
173:175 1 12      0.00
176:177 1 12      2500
178:180 1 12      0.00
1:180 1 13:17     2500

*permj *ijk
1:180 1 1:3       1500
1:180 1 4:6       1700
1:180 1 7:9       3000
1:180 1 10:11     2500
1:3   1 12        0.00
4:7   1 12        2500
8:12  1 12        0.00
13:15 1 12        2500
16:20 1 12        0.00
21:23 1 12        0.32
24:28 1 12        0.00
29:31 1 12        2500
32:36 1 12        0.00
37:39 1 12        2500
40:44 1 12        0.00
45:47 1 12        2500
48:52 1 12        0.00
53:55 1 12        2500
56:60 1 12        0.00
61:63 1 12        2500
64:68 1 12        0.00
69:71 1 12        2500
72:76 1 12        0.00
77:79 1 12        2500
80:84 1 12        0.00
85:87 1 12        2500
88:92 1 12        0.00
93:95 1 12        2500
96:100 1 12       0.00
101:103 1 12      2500
104:108 1 12      0.00
109:111 1 12      2500
112:116 1 12      0.00
117:117 1 12      2500
118:119 1 12      0.00
120:120 1 12      2500
121:122 1 12      0.00
123:123 1 12      2500
124:125 1 12      0.00
126:127 1 12      2500
128:130 1 12      0.00
131:132 1 12      2500
133:135 1 12      0.00
136:137 1 12      2500
138:140 1 12      0.00
141:142 1 12      2500
143:145 1 12      0.00
146:147 1 12      2500
148:150 1 12      0.00
151:152 1 12      2500
153:155 1 12      0.00
156:157 1 12      2500
158:160 1 12      0.00
161:162 1 12      2500
163:165 1 12      0.00
166:167 1 12      2500
168:170 1 12      0.00
171:172 1 12      2500
173:175 1 12      0.00
176:177 1 12      2500
178:180 1 12      0.00
1:180 1 13:17     2500
```

```
*permk *ijk
1:180 1 1:3       100
1:180 1 4:6       500
1:180 1 7:9       1500
1:180 1 10:11     1500
1:3   1 12        0.00
4:7   1 12        1500
8:12  1 12        0.00
13:15 1 12        1500
16:20 1 12        0.00
21:23 1 12        1500
24:28 1 12        0.00
29:31 1 12        1500
32:36 1 12        0.00
37:39 1 12        1500
40:44 1 12        0.00
45:47 1 12        1500
48:52 1 12        0.00
53:55 1 12        1500
56:60 1 12        0.00
61:63 1 12        1500
64:68 1 12        0.00
69:71 1 12        1500
72:76 1 12        0.00
77:79 1 12        1500
80:84 1 12        0.00
85:87 1 12        1500
88:92 1 12        0.00
93:95 1 12        1500
96:100 1 12       0.00
101:103 1 12      1500
104:108 1 12      0.00
109:111 1 12      1500
112:116 1 12      0.00
117:117 1 12      1500
118:119 1 12      0.00
120:120 1 12      1500
121:122 1 12      0.00
123:123 1 12      1500
124:125 1 12      0.00
126:127 1 12      1500
128:130 1 12      0.00
131:132 1 12      1500
133:135 1 12      0.00
136:137 1 12      1500
138:140 1 12      0.00
141:142 1 12      1500
143:145 1 12      0.00
146:147 1 12      1500
148:150 1 12      0.00
151:152 1 12      1500
153:155 1 12      0.00
156:157 1 12      1500
158:160 1 12      0.00
161:162 1 12      1500
163:165 1 12      0.00
166:167 1 12      1500
168:170 1 12      0.00
171:172 1 12      1500
173:175 1 12      0.00
176:177 1 12      1500
178:180 1 12      0.00
1:180 1 13:17     1500

*cpor 9.6e-6 *prpor 3100.0
**cpor 0.45e-6 *prpor 100.0

*rockcp 2.35e6
*cpo    17.0
*thconr 1.250e5

*thconw 1.250e5
*thcono 1.250e5
*thcong 1.250e5
*thconmix *simple

*hlossprop *overbur 2.350e6 1.496e5 *hlosst 18.0 *hlosstdiff 0.1
*hlossprop *underbur 2.350e6 1.496e5 *hlosst 18.0 *hlosstdiff 0.1

**================= FLUID DEFINITIONS ============================

*model 3 3 3

*compname       'WATER'         'OIL'           'CH4'
**              ------------------------------------------
*cmm            0               0.5             0.01604
*porit          0               1360.0          4600.00
*tcrit          0               624.65           -82.55

*molden         0               1950.0          62500.0
*cp             0               5.50e-7            5.5e-7
*ct1            0               8.0e-4           8.0e-4
*ct2            0               0                  0

*kv1            0               0               31914.0
*kv2            0               0                  0
*kv3            0               0                  0
*kv4            0               0               -33.067
*kv5            0               0               -27.71

*cpl1           0               1060              67.2
*cpg1           0               841               35.2
*hvapr          0               1346              1770.0

*visctable

** temp

        12.0            0       60590           450.
        20.0            0       21540           211.3
        30.0            0       7000            46.08
        40.0            0       2261            30.0
        50.0            0       1153            13.76
        60.0            0       558             8.16
        70.0            0       296.4           4.8
        80.0            0       170.3           4.0
```

100.0	0	68.14	3.4
120.0	0	33.25	2.9
140.0	0	18.83	2.5
160.0	0	11.94	2.15
180.0	0	8.256	1.85
200.0	0	6.106	1.45
220.0	0	4.761	1.16
240.0	0	3.872	0.95
260.0	0	3.257	0.79
280.0	0	2.815	0.68
300.0	0	2.488	0.548
2000.0	0	2.488	0.548

```
** ---------- ROCK-FLUID PROPERTIES ----------

*rockfluid

*rpt 1

*swt

**   Sw          Krw           Krow
**  ----       ---------      -------
    0.2000       0.0000        1.0000
    0.2500       0.0000        0.7500
    0.3000       0.0000        0.5650
    0.3500       0.0000        0.4150
    0.4000       0.0000        0.3050
    0.4500       0.0000        0.2250
    0.5000       0.0000        0.1650
    0.5500       0.0000        0.1120
    0.6000       0.0000        0.0680
    0.6500       0.0150        0.0330
    0.7000       0.0500        0.0000
    1.0000       1.0000        0.0000

*slt

**   Sl          Krg           Krog
**  ------      --------      --------
    0.2000       1.0000        0.0000
    0.2500       0.8600        0.0000
    0.3000       0.7300        0.0000
    0.3500       0.6200        0.0000
    0.4000       0.5230        0.0000
    0.4500       0.4380        0.0000
    0.5000       0.3680        0.0000
    0.5500       0.3080        0.0000
    0.6000       0.2550        0.0000
    0.6500       0.1970        0.0000
    0.7000       0.1530        0.0125
    0.7500       0.1130        0.0160
    0.8000       0.0780        0.0210
    0.8500       0.0450        0.0282
    0.9000       0.0100        0.0374
    0.9500       0.0000        0.0500
    1.0000       0.0000        0.0680
```

```
*rpt 2

*swt

**   Sw          Krw          Krow
**  ----      ---------      -------
    0.2000      0.0000       1.0000
    0.2500      0.0000       0.7500
    0.3000      0.0000       0.5650
    0.3500      0.0000       0.4150
    0.4000      0.0000       0.3050
    0.4500      0.0000       0.2250
    0.5000      0.0024       0.1650
    0.5500      0.0075       0.1120
    0.6000      0.0172       0.0680
    0.6500      0.0325       0.0330
    0.7000      0.0500       0.0000
    1.0000      1.0000       0.0000


*slt

**   Sl          Krg          Krog
**  ------     --------     --------
    0.2000      1.0000       0.0000
    0.2500      0.8600       0.0000
    0.3000      0.7300       0.0000
    0.3500      0.6200       0.0000
    0.4000      0.5230       0.0000
    0.4500      0.4380       0.0000
    0.5000      0.3680       0.0000
    0.5500      0.3080       0.0142
    0.6000      0.2550       0.0210
    0.6500      0.1970       0.0315
    0.7000      0.1530       0.0438
    0.7500      0.1130       0.0600
    0.8000      0.0780       0.0790
    0.8500      0.0450       0.1050
    0.9000      0.0100       0.1280
    0.9500      0.0000       0.1640
    1.0000      0.0000       0.2250

*rpt 3

*swt

**   Sw          Krw          Krow
**  ----      ---------      -------
    0.2000      0.0000       1.0000
    0.2500      0.0000       0.7500
    0.3000      0.0000       0.5650
    0.3500      0.0015       0.4150
    0.4000      0.0040       0.3050
    0.4500      0.0080       0.2250
    0.5000      0.0130       0.1650
    0.5500      0.0195       0.1120
    0.6000      0.0280       0.0680
    0.6500      0.0375       0.0330
    0.7000      0.0500       0.0000
    1.0000      1.0000       0.0000

*slt

**   Sl          Krg          Krog
**  ------     --------     --------
    0.2000      1.0000       0.0000
    0.2500      0.8600       0.0000
    0.3000      0.7300       0.0000
    0.3500      0.6200       0.0000
    0.4000      0.5230       0.0150
    0.4500      0.4380       0.0330
    0.5000      0.3680       0.0530
    0.5500      0.3080       0.0780
    0.6000      0.2550       0.1060
    0.6500      0.1970       0.1410
    0.7000      0.1530       0.1810
    0.7500      0.1130       0.2300
    0.8000      0.0780       0.2760
    0.8500      0.0450       0.3290
    0.9000      0.0100       0.3900
    0.9500      0.0000       0.4610
    1.0000      0.0000       0.5650

*rpt 4

*swt

**   Sw          Krw          Krow
**  ----      ---------      -------
    0.2000      0.0000       1.0000
    0.2500      0.0006       0.7500
    0.3000      0.0013       0.5650
    0.3500      0.0024       0.4150
    0.4000      0.0035       0.3050
    0.4500      0.0060       0.2250
    0.5000      0.0090       0.1650
    0.5500      0.0140       0.1120
    0.6000      0.0200       0.0680
    0.6500      0.0300       0.0330
    0.7000      0.0500       0.0000
    1.0000      1.0000       0.0000
```

```
*slt

**   Sl          Krg          Krog
**   ------      --------     --------
     0.2000      1.0000       0.0000
     0.2500      0.8600       0.0000
     0,3000      0.7300       0.0150
     0.3500      0.6200       0.0340
     0.4000      0.5230       0.0560
     0.4500      0.4380       0.0880
     0.5000      0.3680       0.1260
     0.5500      0.3080       0.1700
     0.6000      0.2550       0.2200
     0.6500      0.1970       0.2750
     0.7000      0.1530       0.3400
     0.7500      0.1130       0.4180
     0.8000      0.0780       0.5020
     0.8500      0.0450       0.5960
     0.9000      0.0100       0.7120
     0.9500      0.0000       0.8420
     1.0000      0.0000       1.0000

*rpt 5

*swt

**   Sw          Krw          Krow
**   ----        ---------    -------
     0.2000      0.0000       1.0000
     0.2500      0.0000       0.7500
     0.3000      0.0013       0.5650
     0.3500      0.0033       0.4150
     0.4000      0.0060       0.3050
     0.4500      0.0100       0.2250
     0.5000      0.0148       0.1650
     0.5500      0.0208       0.1120
     0.6000      0.0288       0.0680
     0.6500      0.0375       0.0330
     0.7000      0.0500       0.0000
     1.0000      1.0000       0.0000

*slt

**   Sl          Krg          Krog
**   ------      --------     --------
     0.2000      1.0000       0.0000
     0.2500      0.8600       0.0000
     0.3000      0.7300       0.0000
     0.3500      0.6200       0.0150
     0.4000      0.5230       0.0340
     0.4500      0.4380       0.0600
     0.5000      0.3680       0.0910
     0.5500      0.3080       0.1260
     0.6000      0.2550       0.1700
     0.6500      0.1970       0.2190
     0.7000      0.1530       0.2700
     0.7500      0.1130       0.3260
     0.8000      0.0780       0.3940
     0.8500      0.0450       0.4660
     0.9000      0.0100       0.5510
     0.9500      0.0000       0.6400
     1.0000      0.0000       0.7500
```

```
*krtype *ijk
1:180 1 1:3      1
1:180 1 4:6      2
1:180 1 7:9      3
1:180 1 10:11    4
1:3   1 12       1
4:7   1 12       5
8:12  1 12       1
13:15 1 12       5
16:20 1 12       1
21:23 1 12       5
24:28 1 12       1
29:31 1 12       5
32:36 1 12       1
37:39 1 12       5
40:44 1 12       1
45:47 1 12       5
48:52 1 12       1
53:55 1 12       5
56:60 1 12       1
61:63 1 12       5
64:68 1 12       1
69:71 1 12       5
72:76 1 12       1
77:79 1 12       5
80:84 1 12       1
85:87 1 12       5
88:92 1 12       1
93:95 1 12       5
96:100 1 12      1
101:103 1 12     5
104:108 1 12     1
109:111 1 12     5
112:116 1 12     1
117:117 1 12     5
118:119 1 12     1
120:120 1 12     5
121:122 1 12     1
123:123 1 12     5
124:125 1 12     1
126:127 1 12     5
128:130 1 12     1
131:132 1 12     5
133:135 1 12     1
136:137 1 12     5
138:140 1 12     1
141:142 1 12     5
143:145 1 12     1
146:147 1 12     5
148:150 1 12     1
151:152 1 12     5
153:155 1 12     1
156:157 1 12     5
158:160 1 12     1
161:162 1 12     5
163:165 1 12     1
166:167 1 12     5
168:170 1 12     1
171:172 1 12     5
173:175 1 12     1
176:177 1 12     5
178:180 1 12     1
1:180 1 13:17    5
```

File: Burnt_Lake_Study.dat 8

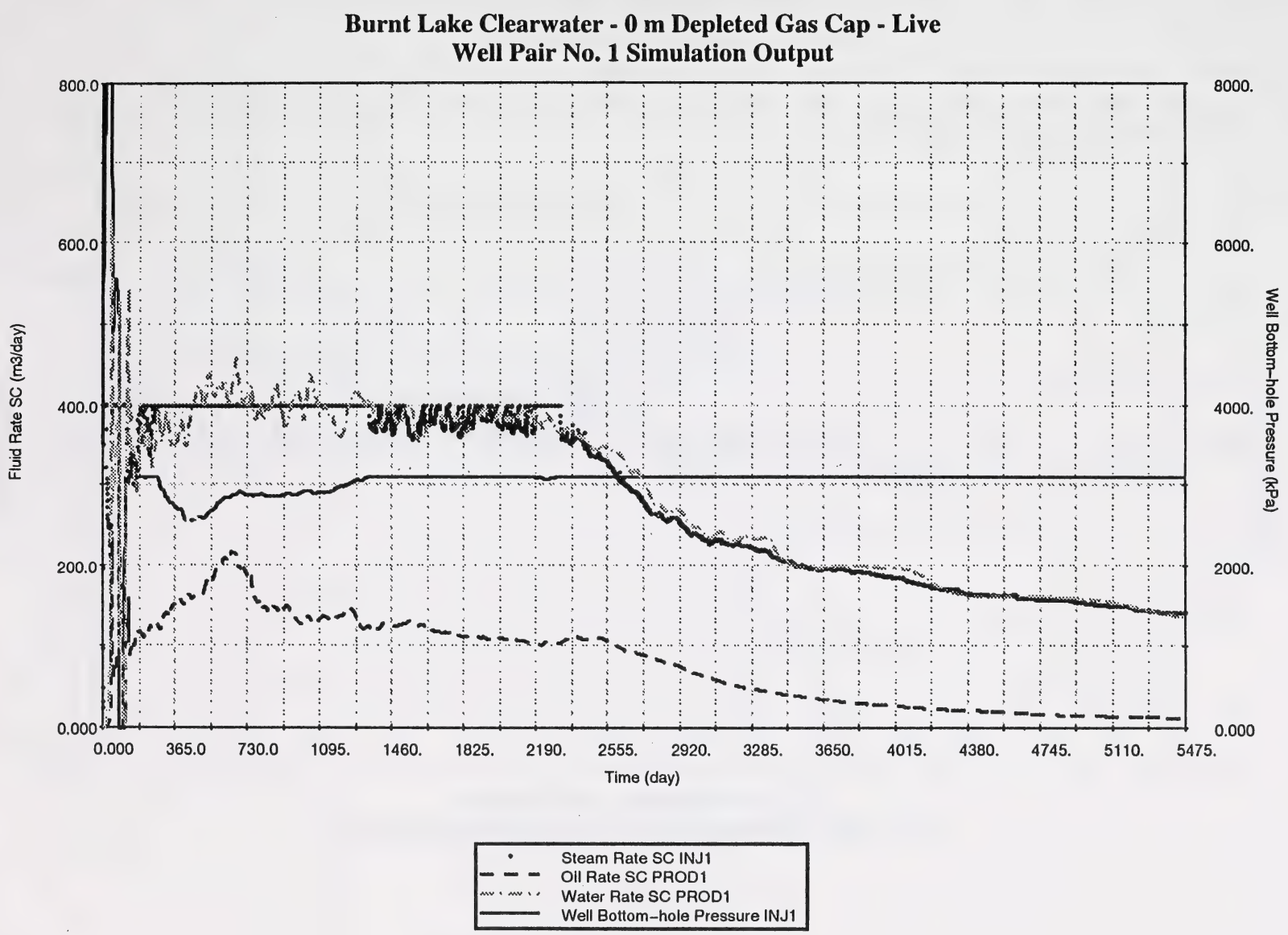
```
** ---------------------- INTIAL CONDITIONS -------------------------

*initial

*pres *con 3100.0

*temp *con 12.0

*sg *ijk 1:180 1 1:17 0.00

*so *ijk
1:180 1 1:3       0.40
1:180 1 4:6       0.55
1:180 1 7:9       0.70
1:180 1 10:11     0.80
1:3   1 12        0.40
4:7   1 12        0.75
8:12  1 12        0.40
13:15 1 12        0.75
16:20 1 12        0.40
21:23 1 12        0.75
24:28 1 12        0.40
29:31 1 12        0.75
32:36 1 12        0.40
37:39 1 12        0.75
40:44 1 12        0.40
45:47 1 12        0.75
48:52 1 12        0.40
53:55 1 12        0.75
56:60 1 12        0.40
61:63 1 12        0.75
64:68 1 12        0.40
69:71 1 12        0.75
72:76 1 12        0.40
77:79 1 12        0.75
80:84 1 12        0.40
85:87 1 12        0.75
88:92 1 12        0.40
93:95 1 12        0.75
96:100 1 12       0.40
101:103 1 12      0.75
104:108 1 12      0.40
109:111 1 12      0.75
112:116 1 12      0.40
117:117 1 12      0.75
118:119 1 12      0.40
120:120 1 12      0.75
121:122 1 12      0.40
123:123 1 12      0.75
124:125 1 12      0.40
126:127 1 12      0.75
128:130 1 12      0.40
131:132 1 12      0.75
133:135 1 12      0.40
136:137 1 12      0.75
138:140 1 12      0.40
141:142 1 12      0.75
143:145 1 12      0.40
146:147 1 12      0.75
148:150 1 12      0.40
151:152 1 12      0.75
153:155 1 12      0.40
156:157 1 12      0.75
158:160 1 12      0.40
161:162 1 12      0.75
163:165 1 12      0.40
166:167 1 12      0.75
168:170 1 12      0.40
171:172 1 12      0.75
173:175 1 12      0.40
176:177 1 12      0.75
178:180 1 12      0.40
1:180 1 13:17     0.75

*molefrac *oil *con  0.0 0.86 0.14
**molefrac *gas *con 0.0 0.0  1.0
```

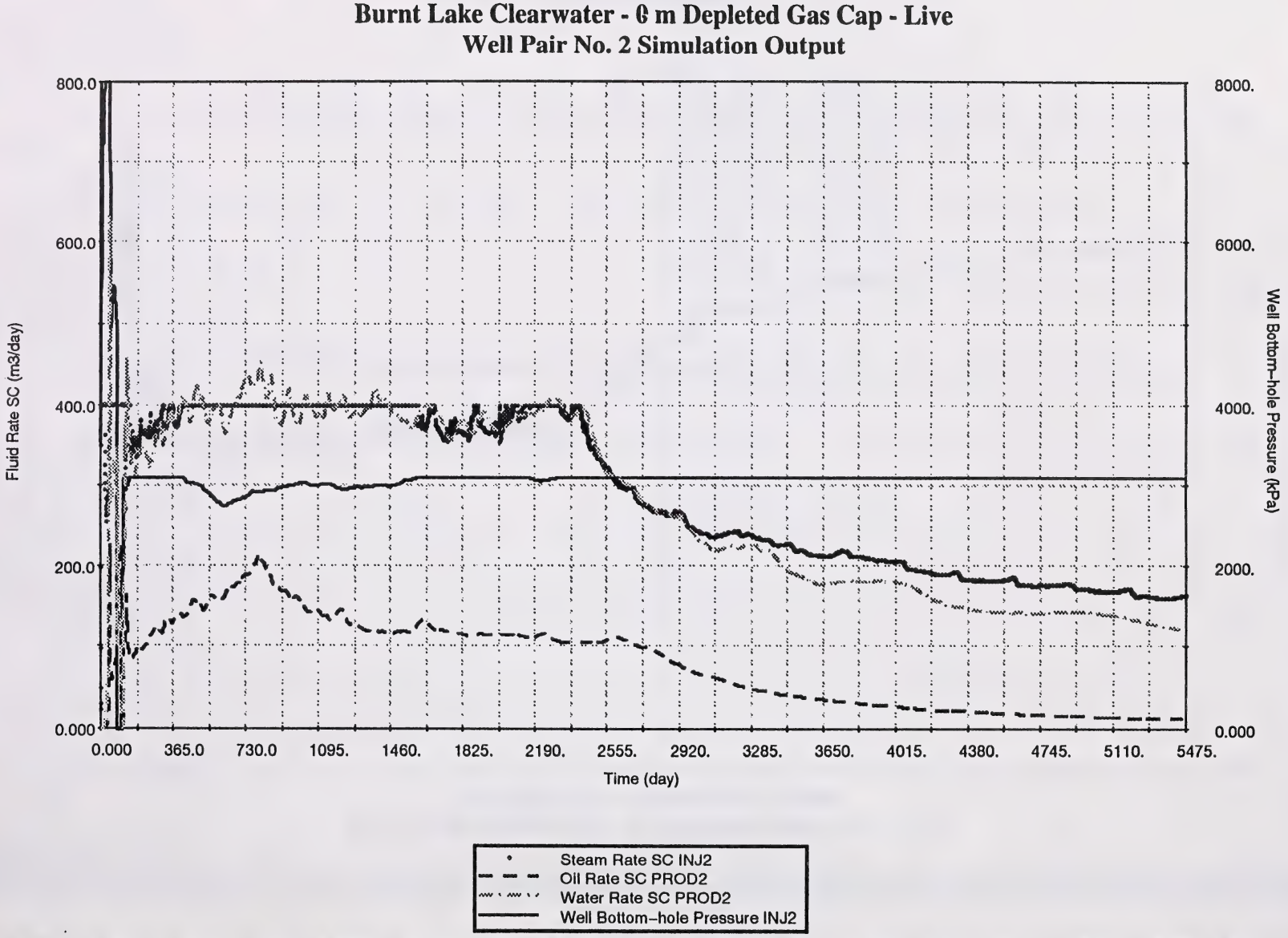
```
**  ----------  NUMERICAL CONTROL  ----------------------

*numerical

*aim            *off
*dtmax          15.0
*maxsteps       5000
*north          8
*itermax        60
*unrelax        -1
*sdegree        2
*sorder         rcmrb
*mintemp        1
*minpres        50
*norm           *press 400.0
                *satur 0.2
                *temp 50.0      *y      0.2     *x      0.2
*converge       *press 30.0
                *satur 0.04     *y      0.04    *x      0.04
                *temp 3.0
*pvtoscmax      4
```

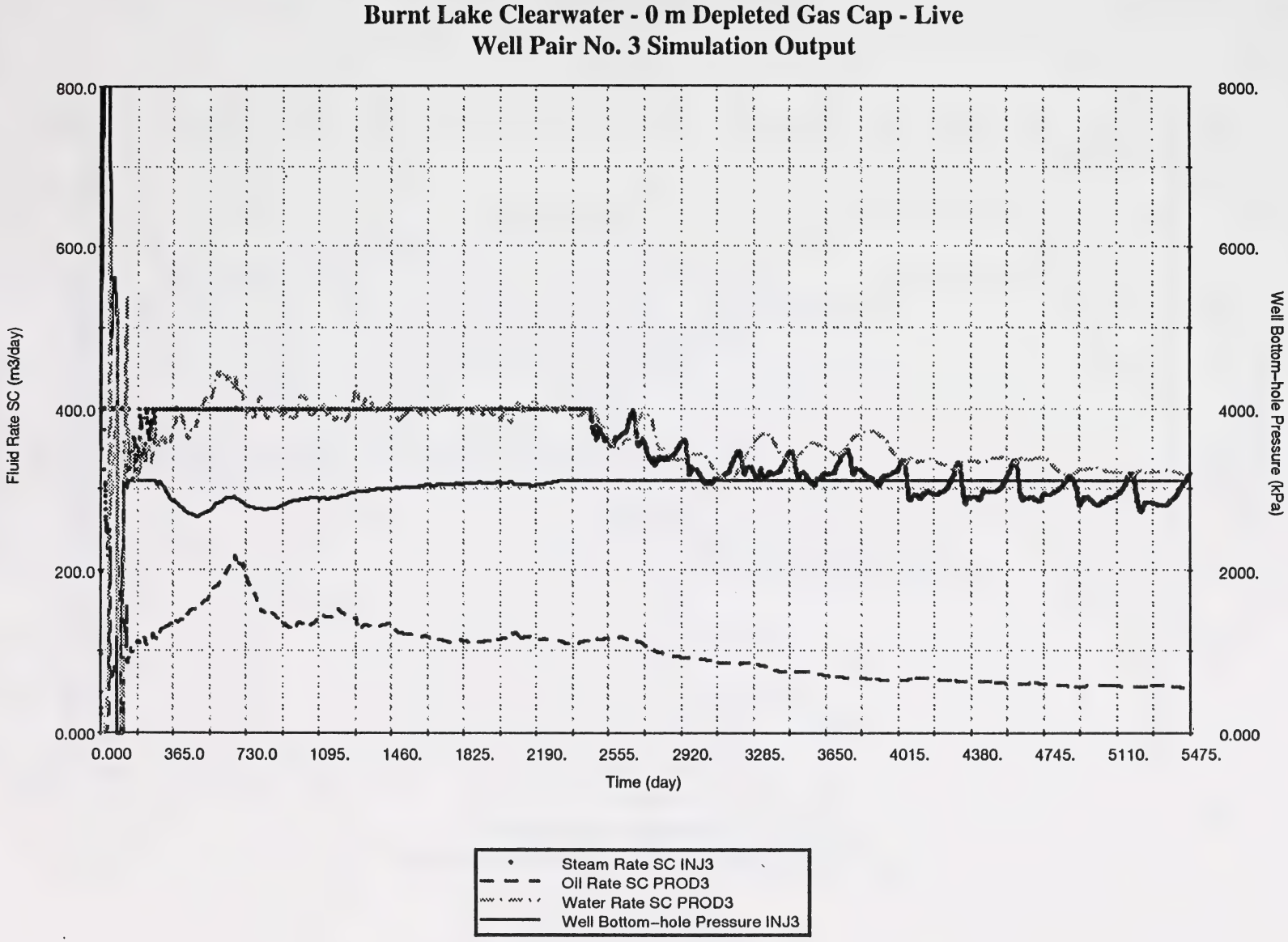
```
**  ----------  RECURRENT DATA  ----------------------

*run
*date 2000 1 1    *dtwell 1.0E-2

*well 1 'INJ1'   *frac 0.500
*injector *mobweight 1
*tinjw 295. *qual 0.98
*operate *max *bhp 8000.
*operate *max *water 400.
*operate *max *bhp 8000.
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 1
1:1 1:1 7
*uhtr *ijk
1:1 1:1 7  0.110e9
*tmpset *ijk
1:1 1:1 7   257.0

*well 2 'PROD1' *frac 0.500
*producer 2
*operate *min *bhp 3000.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 2
1:1  1:1  4
*uhtr *ijk
1:1  1:1  4     0.879e6
*tmpset *ijk
1:1  1:1  4     235.0

*well 3 'INJ2'
*injector *mobweight 3
*tinjw 295. *qual 0.98
*operate *max *bhp 8000.
*operate *max *water 400.
*operate *max *bhp 8000.
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 3
46:46 1:1 7
*uhtr *ijk
46:46 1:1 7  0.110e9
*tmpset *ijk
46:46 1:1 7   257.0

*well 4 'PROD2'
*producer 4
*operate *min *bhp 3000.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 4
46:46  1:1  4
*uhtr *ijk
46:46  1:1  4     0.879e6
*tmpset *ijk
46:46  1:1  4     235.0
```

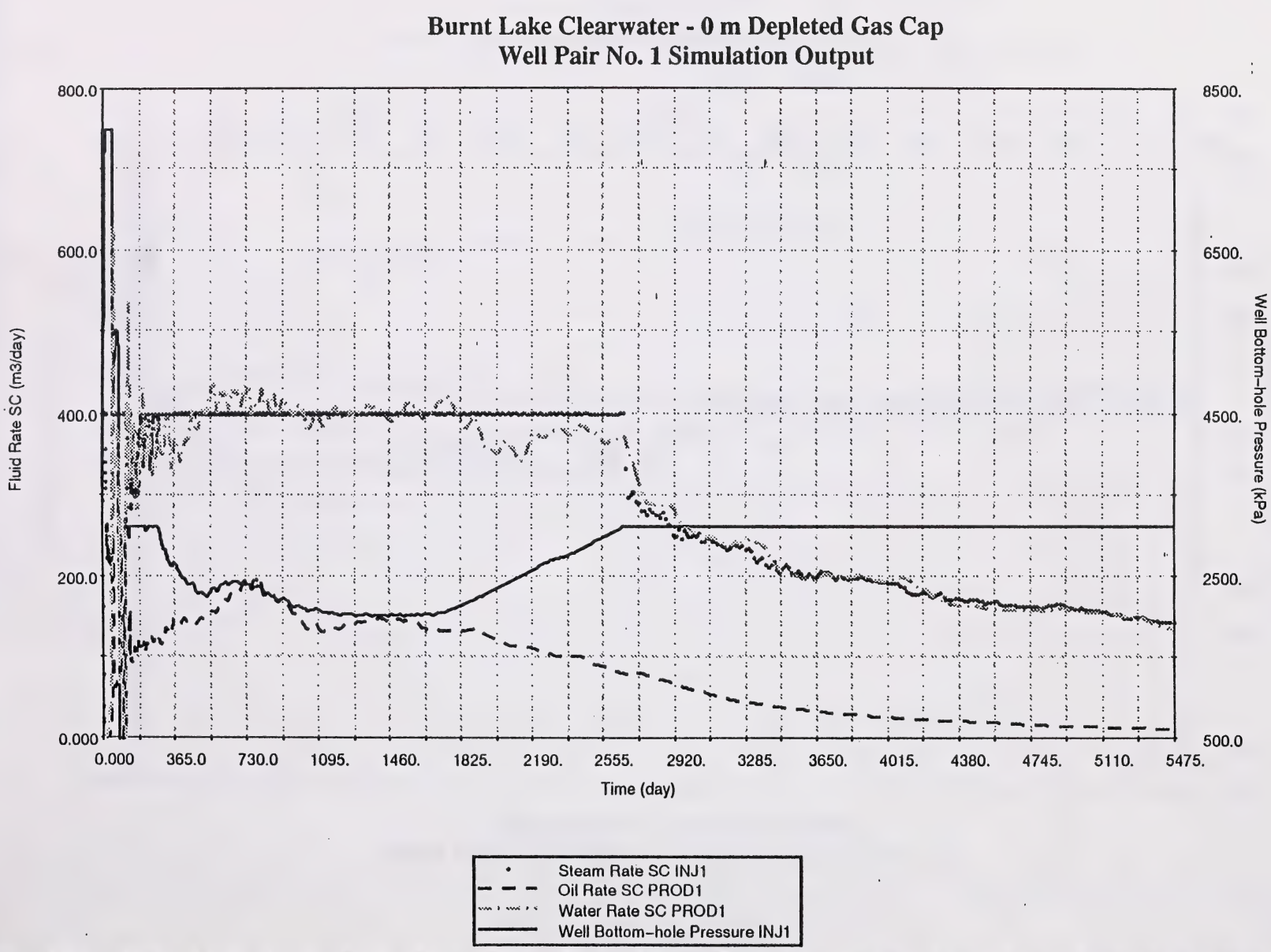
```
*well 5 'INJ3'
*injector *mobweight 5
*tinjw 295. *qual 0.98
*operate *max *bhp 8000.
*operate *max *water 400.
*operate *max *bhp 8000.
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 5
91:91 1:1 7
*uhtr *ijk
91:91 1:1 7  0.110e9
*tmpset *ijk
91:91 1:1 7   257.0

*well 6 'PROD3'
*producer 6
*operate *min *bhp 3000.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 6
91:91  1:1  4
*uhtr *ijk
91:91  1:1  4     0.879e6
*tmpset *ijk
91:91  1:1  4     235.0

** *well 7 'GAS'
** *producer 7
** *operate *min *bhp 3100.0
** *operate *max *gas 100000.
** *operate *min *bhp 3100.0
** *geometry *j 0.110 0.363 0.5 0.0
** *perf *geo 7
** 180:180  1:1  17

*group  'INJ1' 'INJ2' 'INJ3' *attachto 'INJECTION'
*group  'PROD1' 'PROD2' 'PROD3' *attachto 'PRODUCTION'

*dtmax 1.0

*time 10.0
*time 20.0
*time 36.5      **0.1 yrs
*time 50.0
*time 60.0
*time 70.0
*time 80.0

*dtwell 0.001

*shutin 1 3 5

*producer 2
*operate *min *bhp 3000.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 2
1:1  1:1  4
*uhtr *con 0.0

*producer 4
*operate *min *bhp 3000.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 4
46:46  1:1  4
*uhtr *con 0.0

*producer 6
*operate *min *bhp 3000.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 6
91:91  1:1  4
*uhtr *con 0.0

*time 81.0
*time 85.0
*time 90.0
*time 100.0
*time 105.0

*injector *mobweight 1
*tinjw 235. *qual 0.98
*operate *max *bhp 3100.
*operate *max *water 400.
*operate *max *bhp 3100.
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 1
1:1 1:1 7

*producer 2
*operate *min *bhp 2800.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 2
1:1  1:1  4

*injector *mobweight 3
*tinjw 235. *qual 0.98
*operate *max *bhp 3100.
*operate *max *water 400.
*operate *max *bhp 3100.
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 3
46:46 1:1 7

*producer 4
*operate *min *bhp 2800.0
*operate *max *steam 0.5
```

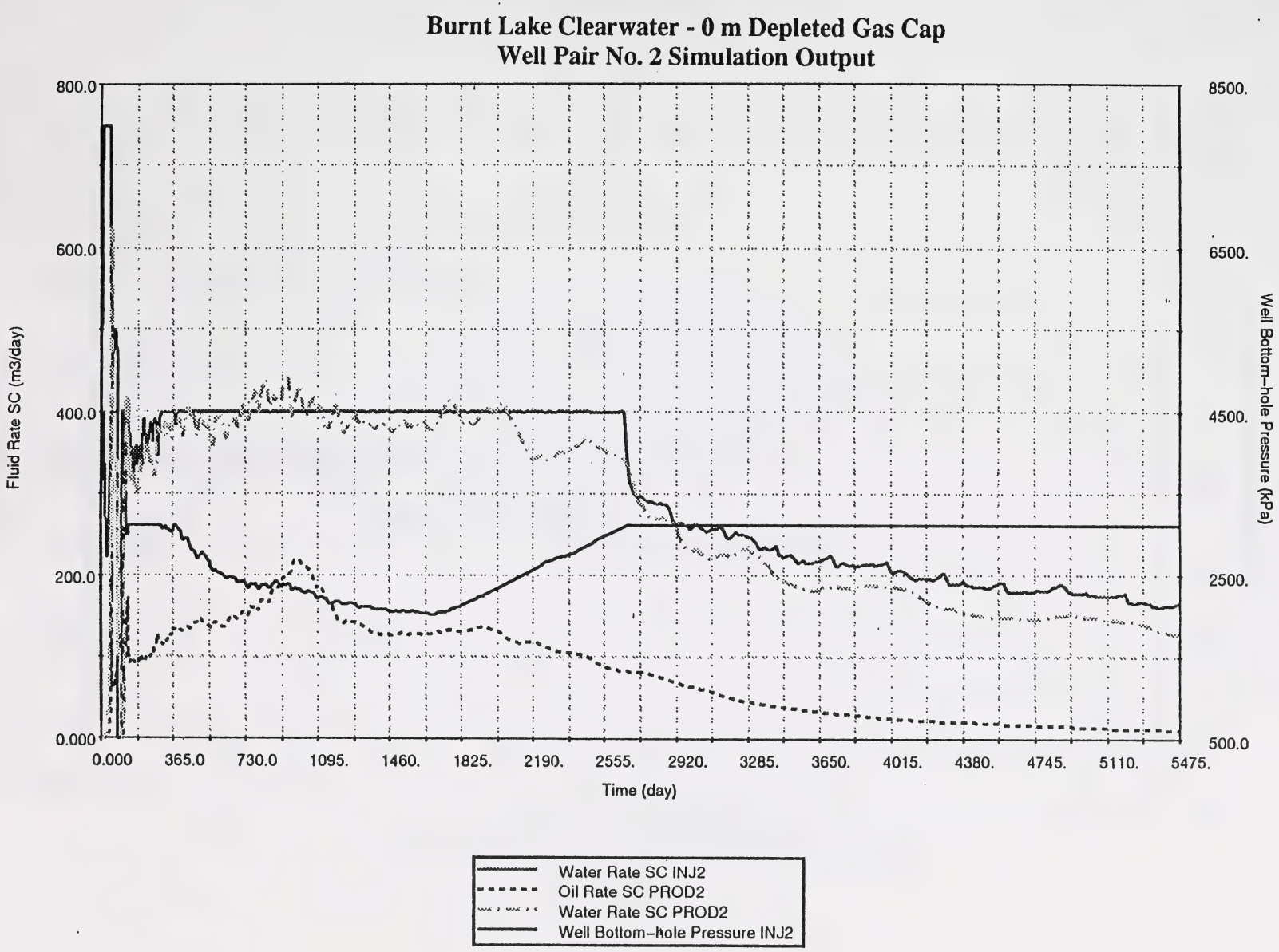
```
*operate *max *liquid 800.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 4
46:46  1:1  4

*injector *mobweight 5
*tinjw 235. *qual 0.98
*operate *max *bhp 3100.
*operate *max *water 400.
*operate *max *bhp 3100.
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 5
91:91 1:1 7

*producer 6
*operate *min *bhp 2800.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.363 0.5 0.0
*perf *geo 6
91:91  1:1  4

*time 120.0
*time 150.0
*time 182.5
*time 210.0
*time 250.0
*time 300.0
*time 350.0
*time 365.0     **1.0 yr

*dtmax 15.0

*time 400.0
*time 438.0     **1.2 yrs
*time 547.5     **1.5 yrs
*time 657.0     **1.8 yrs
*time 730.0           **2.0 yrs
*time 803.0     **2.2 yrs
*time 912.5     **2.5 yrs
*time 1022.0    **2.8 yrs
*time 1095.0          **3.0 yrs
*time 1168.0    **3.2 yrs
*time 1277.5    **3.5 yrs
*time 1387.0    **3.8 yrs
*time 1460.0          **4.0 yrs
*time 1533.0    **4.3 yrs
*time 1565.0          ** 3 yrs operating time
*time 1642.5    **4.5 yrs
*time 1752.0    **4.8 yrs
*time 1825.0          ** 5.0 yrs
*time 1898.0    **5.2 yrs
*time 2007.5    **5.5 yrs
*time 2117.0    **5.8 yrs
*time 2190.0          ** 6.0 yrs
*time 2263.0    **6.2 yrs
*time 2372.5    **6.5 yrs
*time 2482.0    **6.8 yrs
*time 2555.0          ** 7.0 yrs
*time 2628.0    **7.2 yrs
*time 2701.0    **7.4 yrs
*time 2735.0              ** *shutin 1 3 5      **7.5 yrs
*time 2847.0    **7.8 yrs
*time 2920.0          ** 8.0 yrs
*time 2993.0    **8.2 yrs
*time 3102.0    **8.5 yrs
*time 3212.0    **8.8 yrs
*time 3285.0          ** 9.0 yrs
*time 3358.0    **9.2 yrs
*time 3467.0    **9.5 yrs
*time 3650.0          ** 10.0 yrs
*time 3832.0    **10.5 yrs
*time 4014.0    **11.0 yrs
*time 4196.0    **11.5 yrs
*time 4378.0    **12.0 yrs
*time 4560.0    **12.5 yrs
*time 4742.0    **13.0 yrs
*time 4924.0    **13.5 yrs
*time 5106.0    **14.0 yrs
*time 5288.0    **14.5 yrs
*time 5470.0    **15.0 yrs

*stop
```

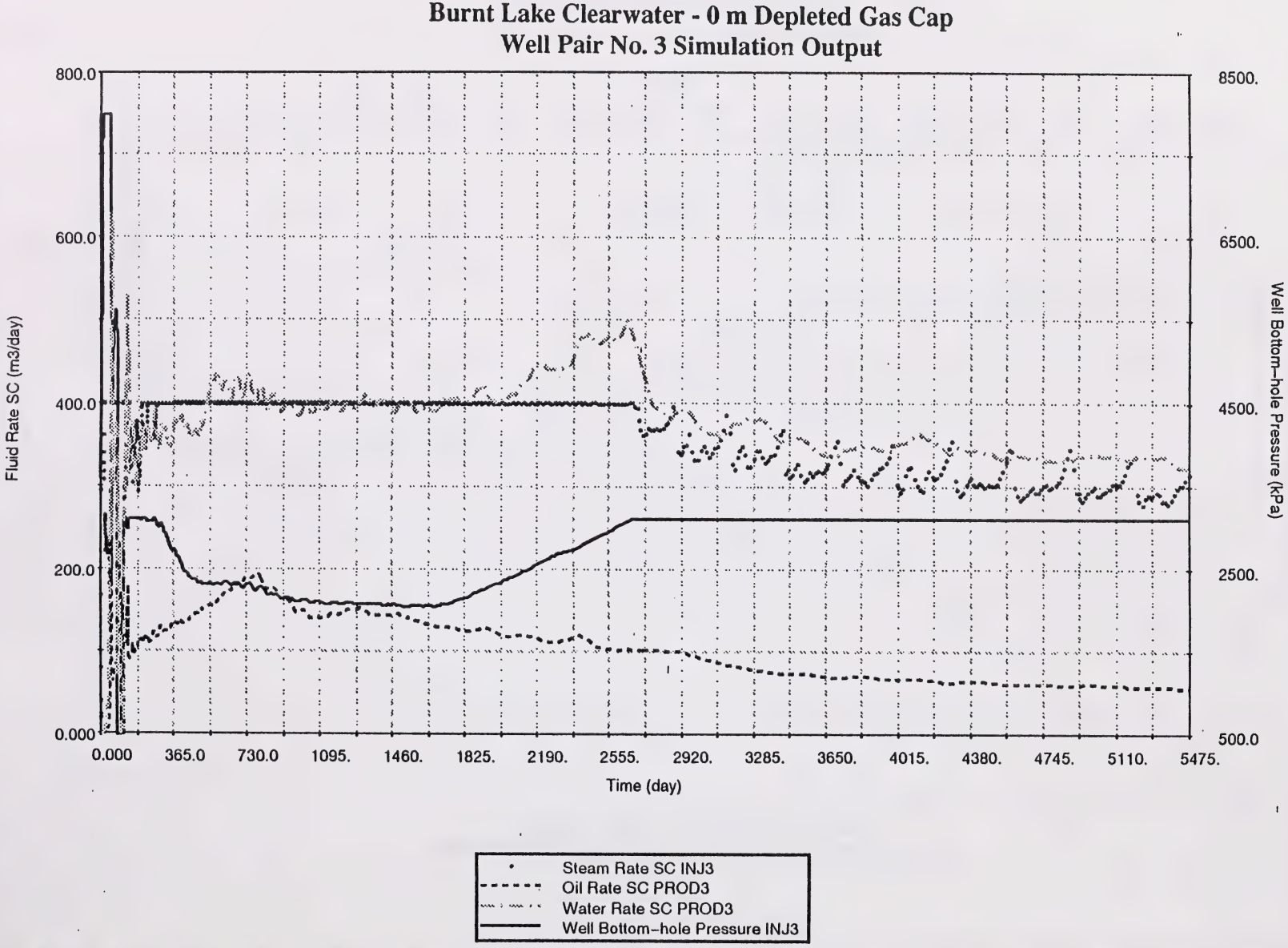

Burnt Lake Clearwater - 0 m Depleted Gas Cap - Live
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8000.
6000.
4000.
2000.
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1


Burnt Lake Clearwater - 6 m Depleted Gas Cap - Live
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8000.
6000.
4000.
2000.
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2

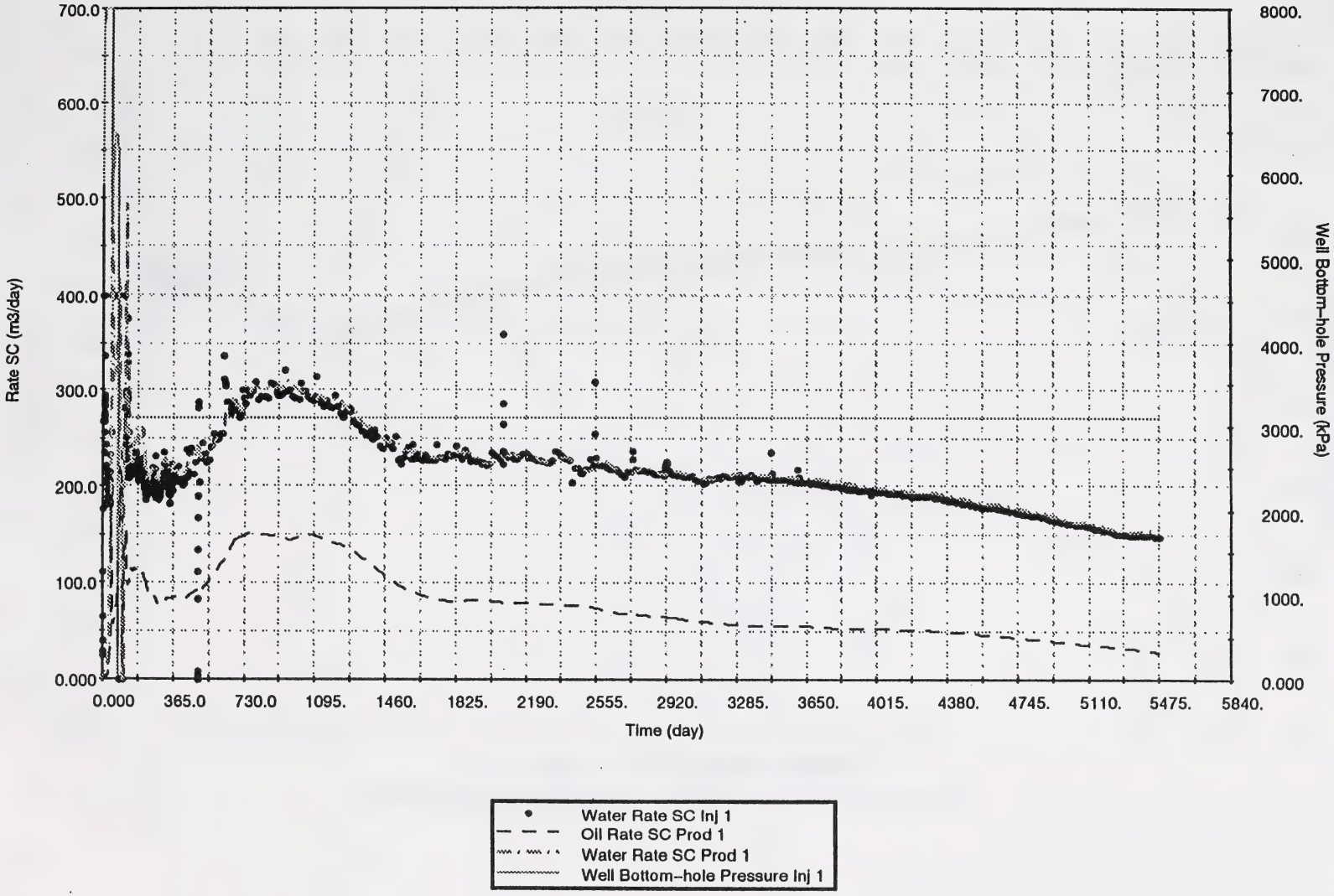

Burnt Lake Clearwater - 0 m Depleted Gas Cap - Live
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8000.
6000.
4000.
2000.
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3

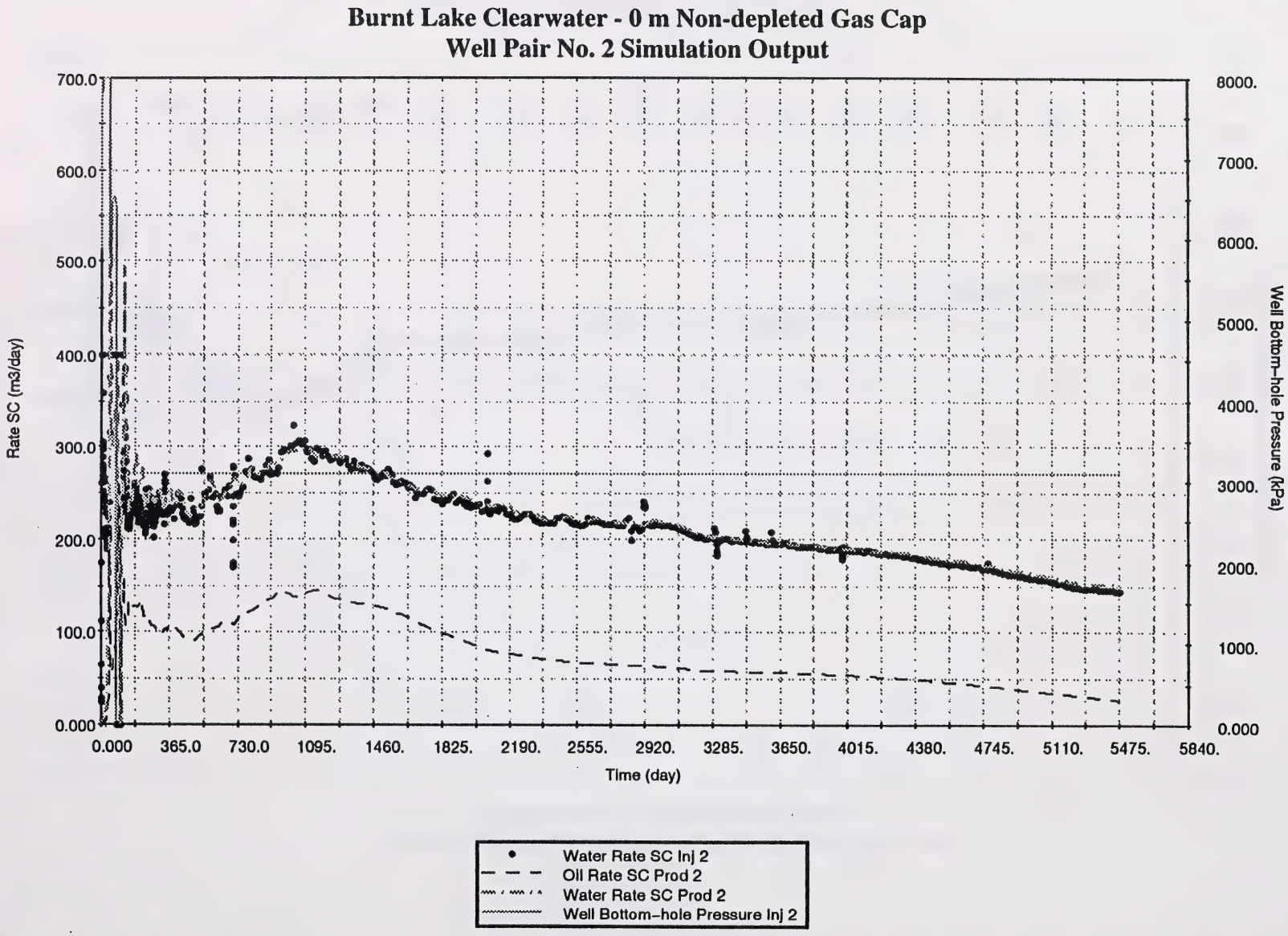

Burnt Lake Clearwater - 0 m Depleted Gas Cap
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8500.
6500.
4500.
2500.
500.0
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1

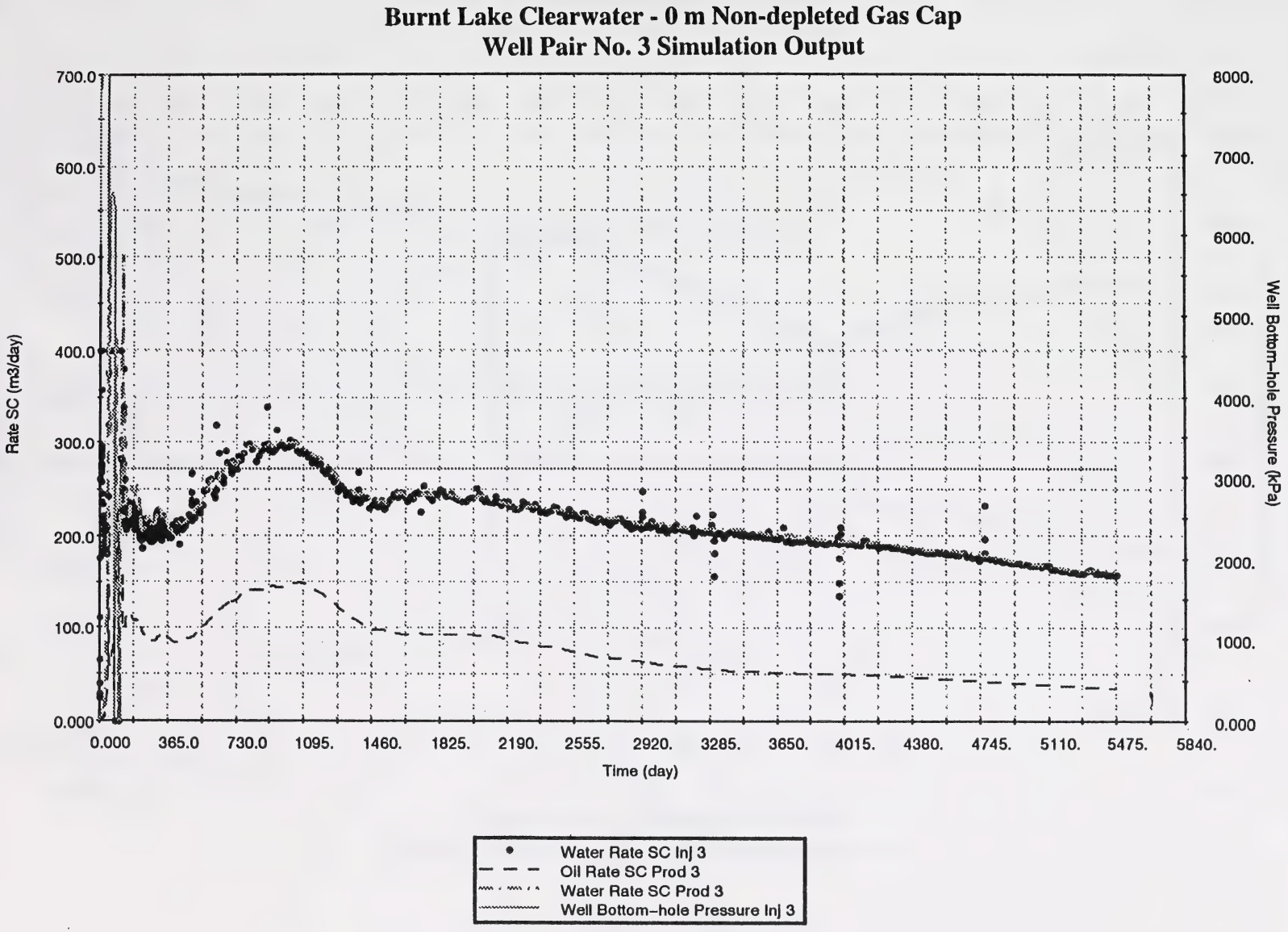

Burnt Lake Clearwater - 0 m Depleted Gas Cap
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8500.
6500.
4500.
2500.
500.0
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Water Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2

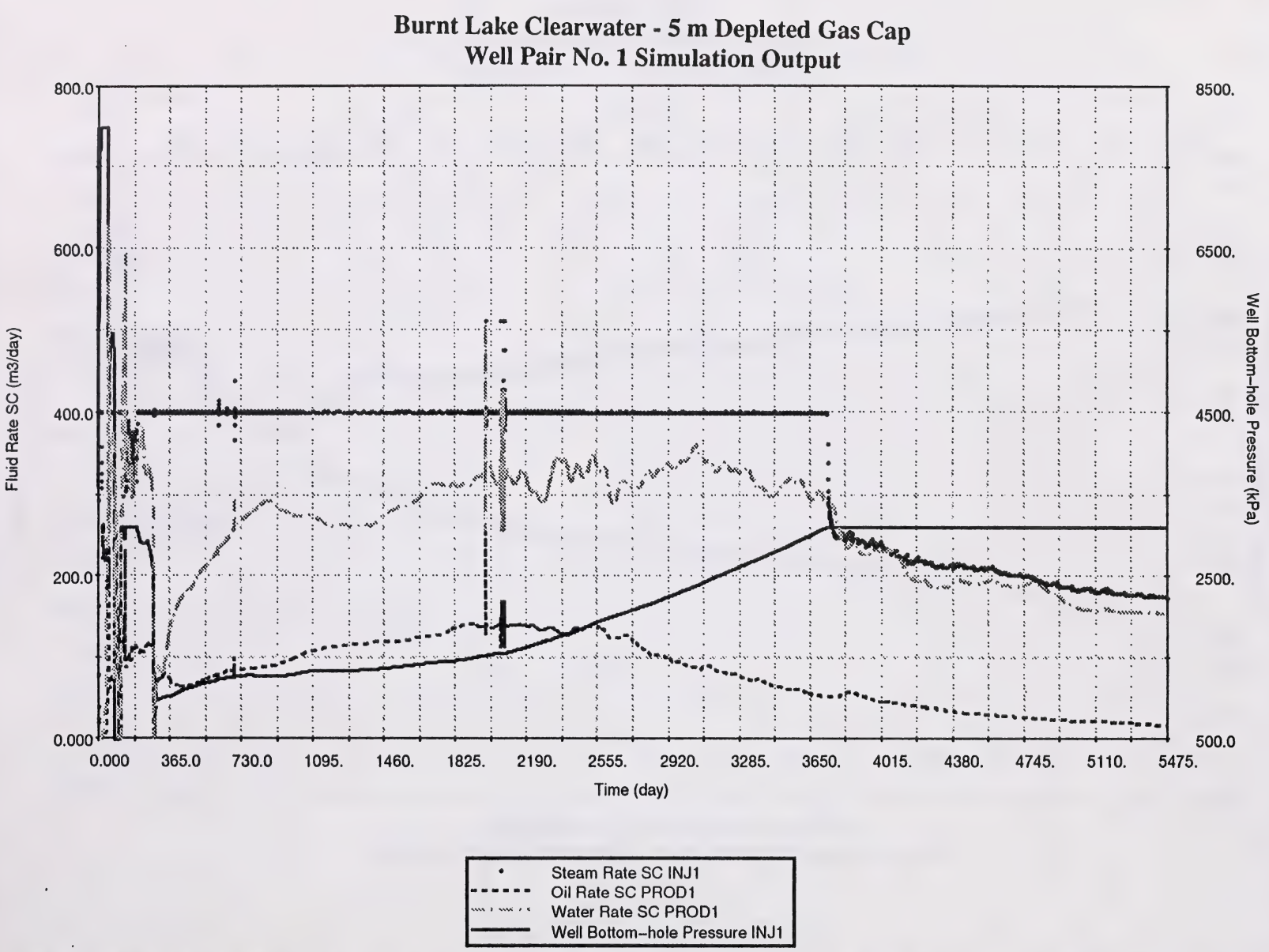

Burnt Lake Clearwater - 0 m Depleted Gas Cap
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8500.
6500.
4500.
2500.
500.0
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3

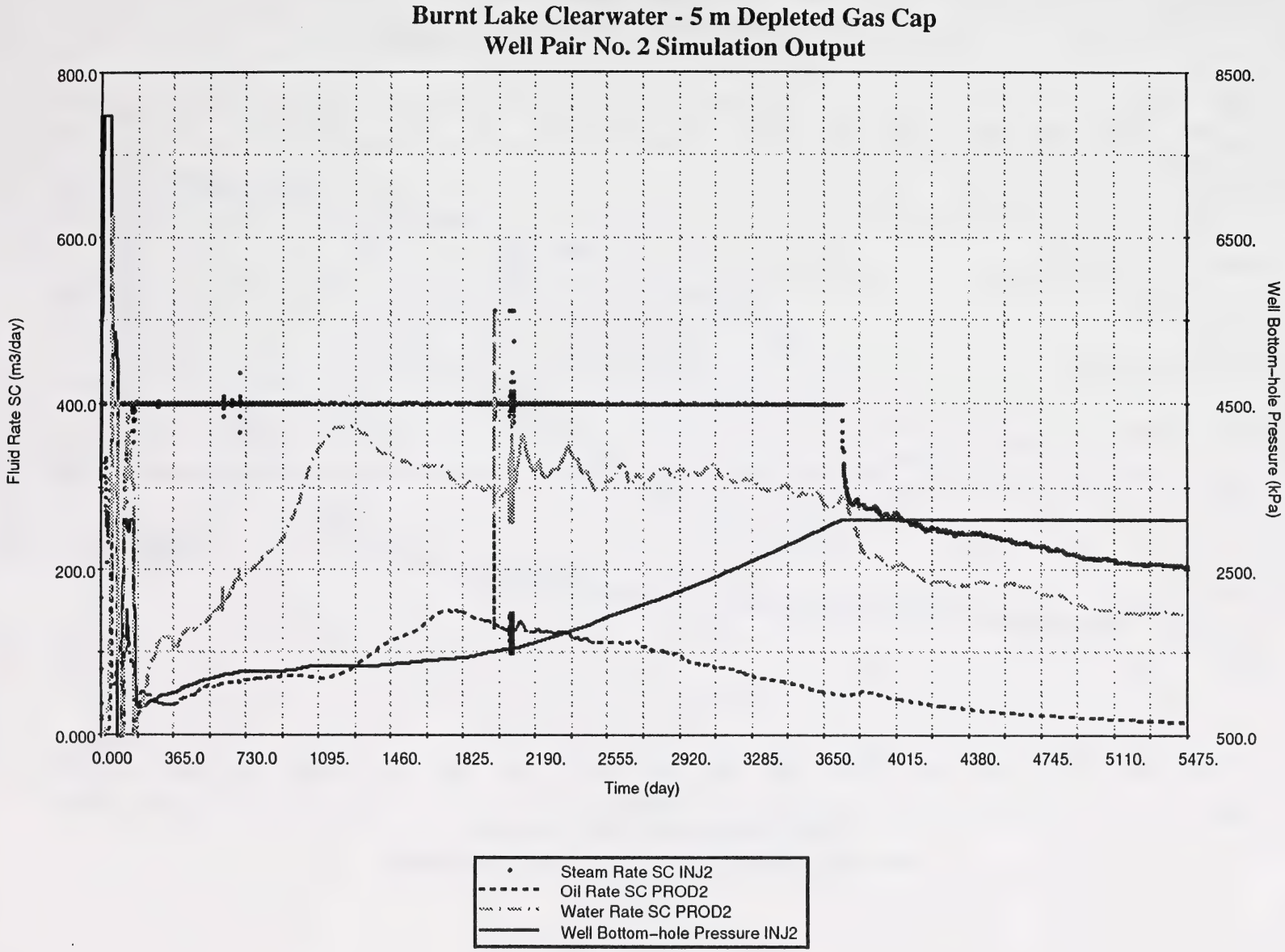
Burnt Lake Clearwater - 0 m Non-depleted Gas Cap
Well Pair No. 1 Simulation Output

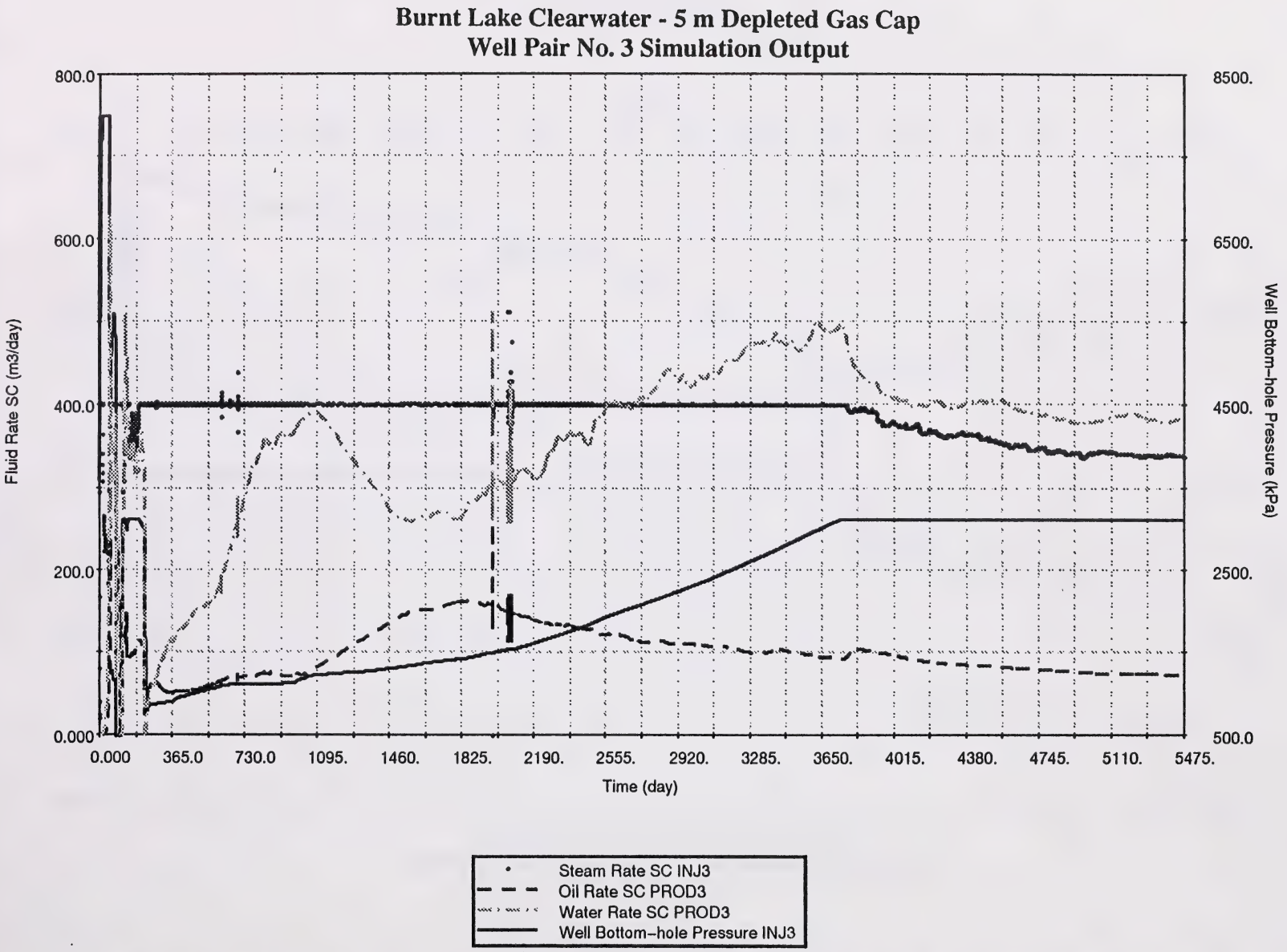


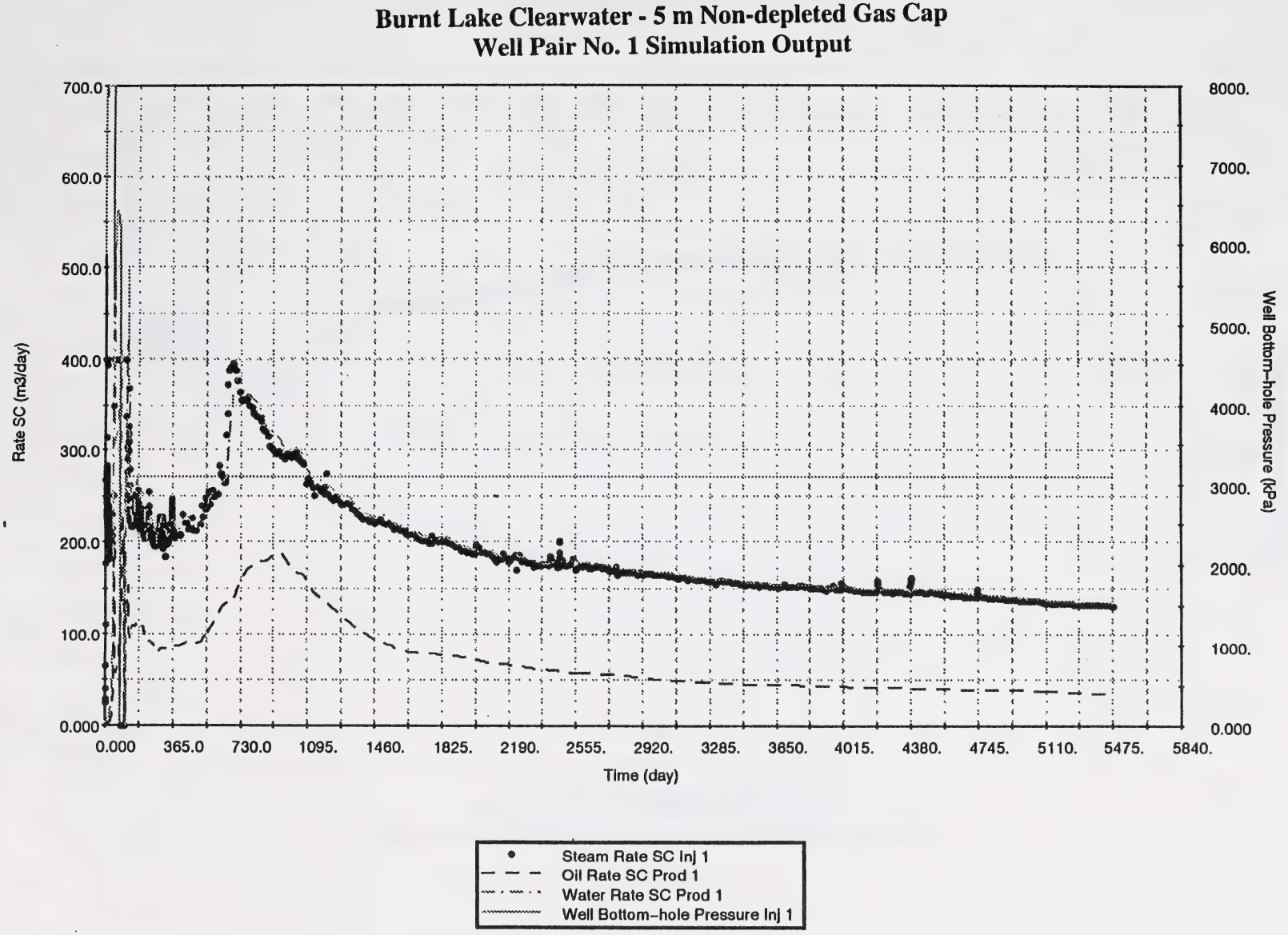

Burnt Lake Clearwater - 0 m Non-depleted Gas Cap
Well Pair No. 2 Simulation Output
Rate SC (m3/day)
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
8000.
7000.
6000.
5000.
4000.
3000.
2000.
1000.
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Water Rate SC Inj 2
Oil Rate SC Prod 2
Water Rate SC Prod 2
Well Bottom-hole Pressure Inj 2

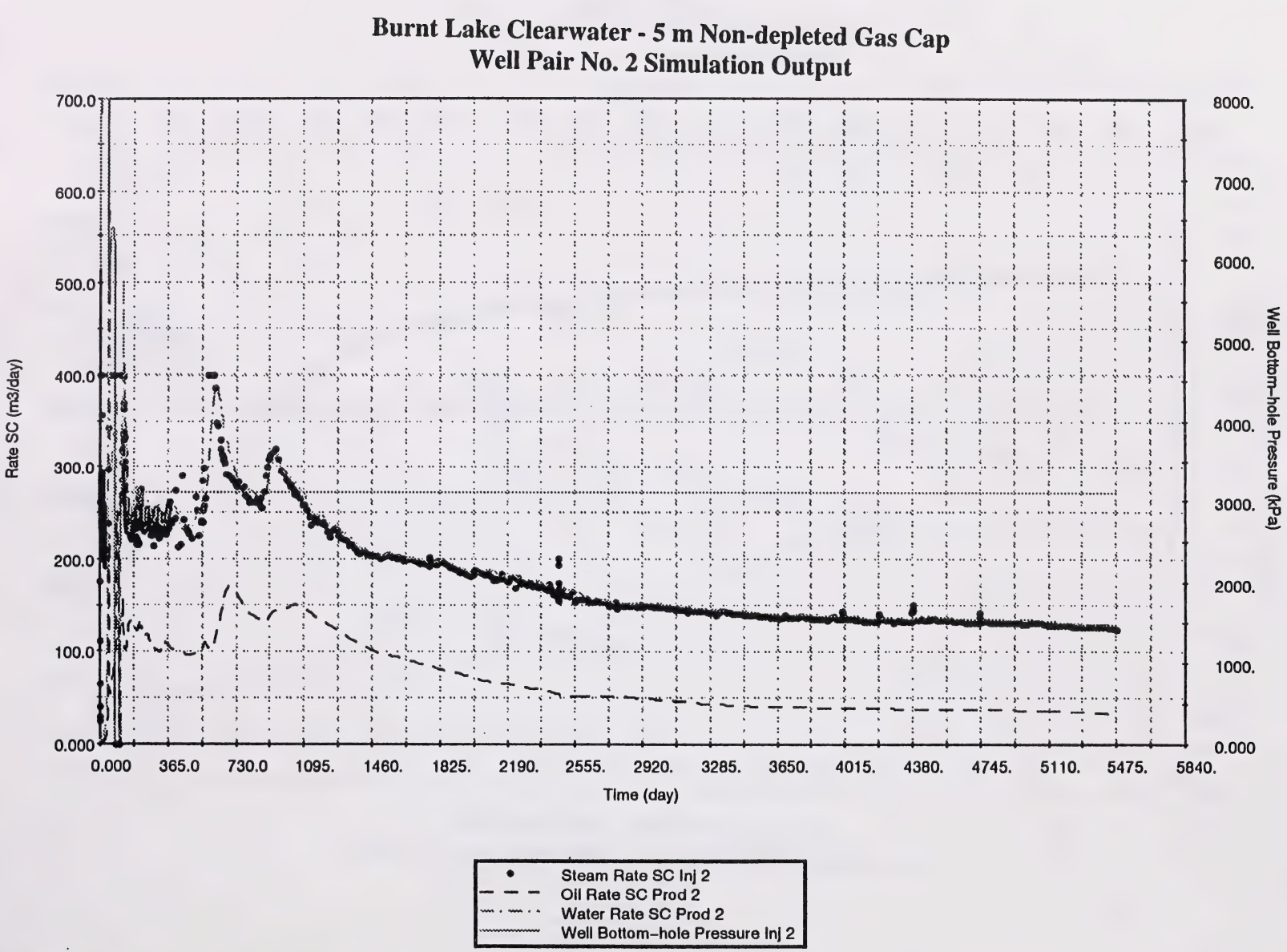

Burnt Lake Clearwater - 0 m Non-depleted Gas Cap
Well Pair No. 3 Simulation Output
Rate SC (m3/day)
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
8000.
7000.
6000.
5000.
4000.
3000.
2000.
1000.
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Water Rate SC Inj 3
Oil Rate SC Prod 3
Water Rate SC Prod 3
Well Bottom-hole Pressure Inj 3

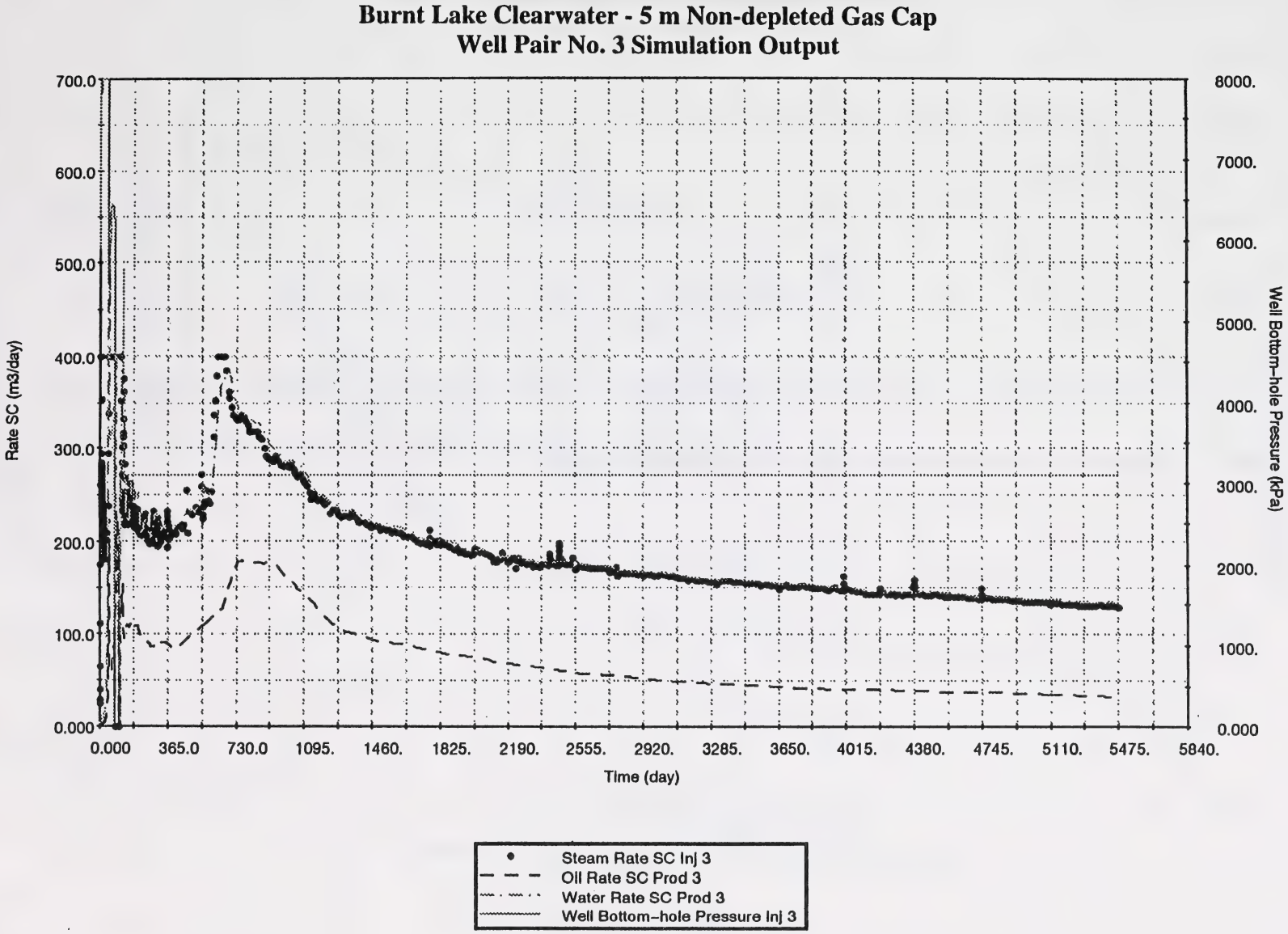

Burnt Lake Clearwater - 5 m Depleted Gas Cap
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8500.
6500.
4500.
2500.
500.0
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1

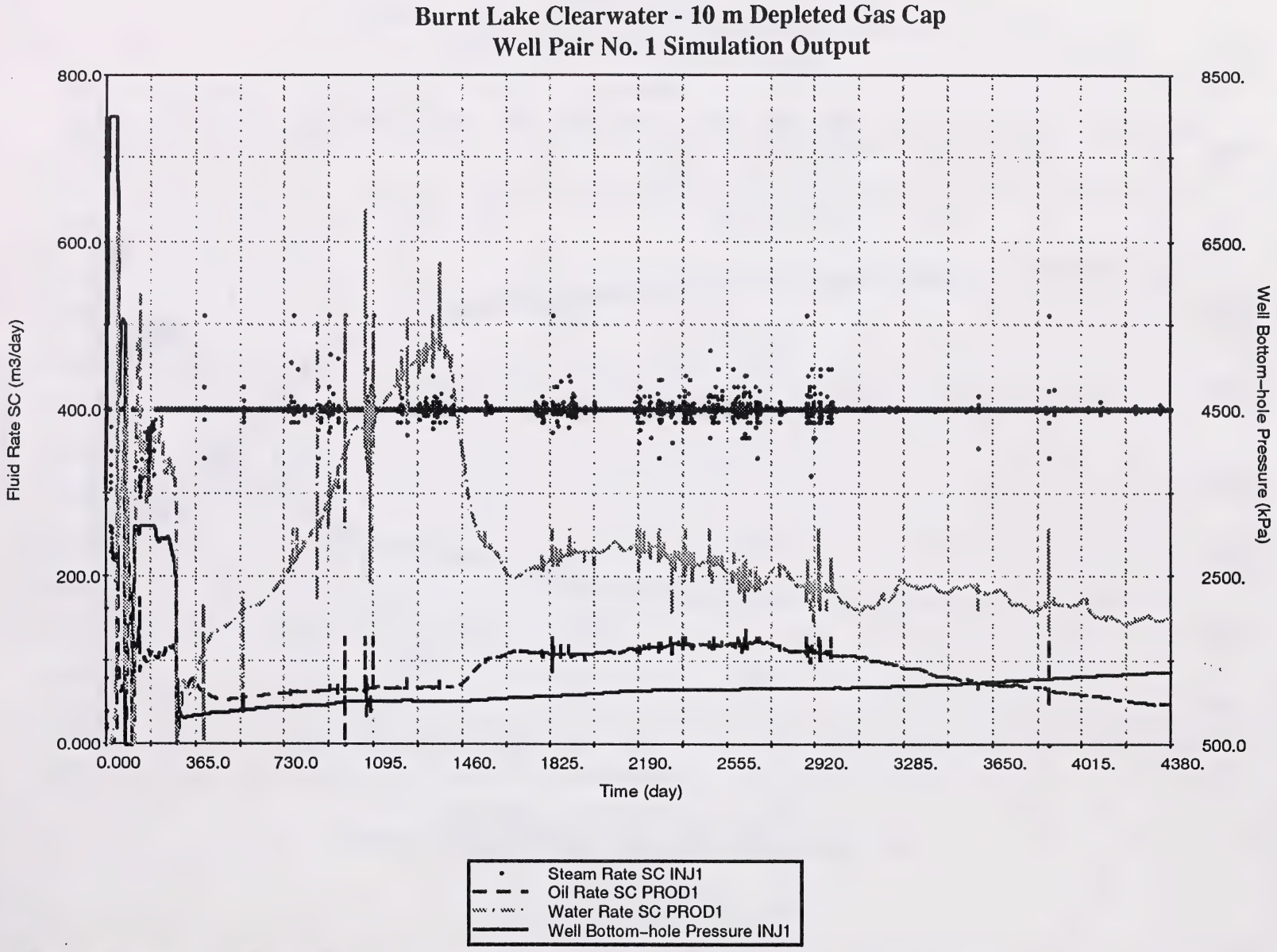

Burnt Lake Clearwater - 5 m Depleted Gas Cap
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8500.
6500.
4500.
2500.
500.0
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2

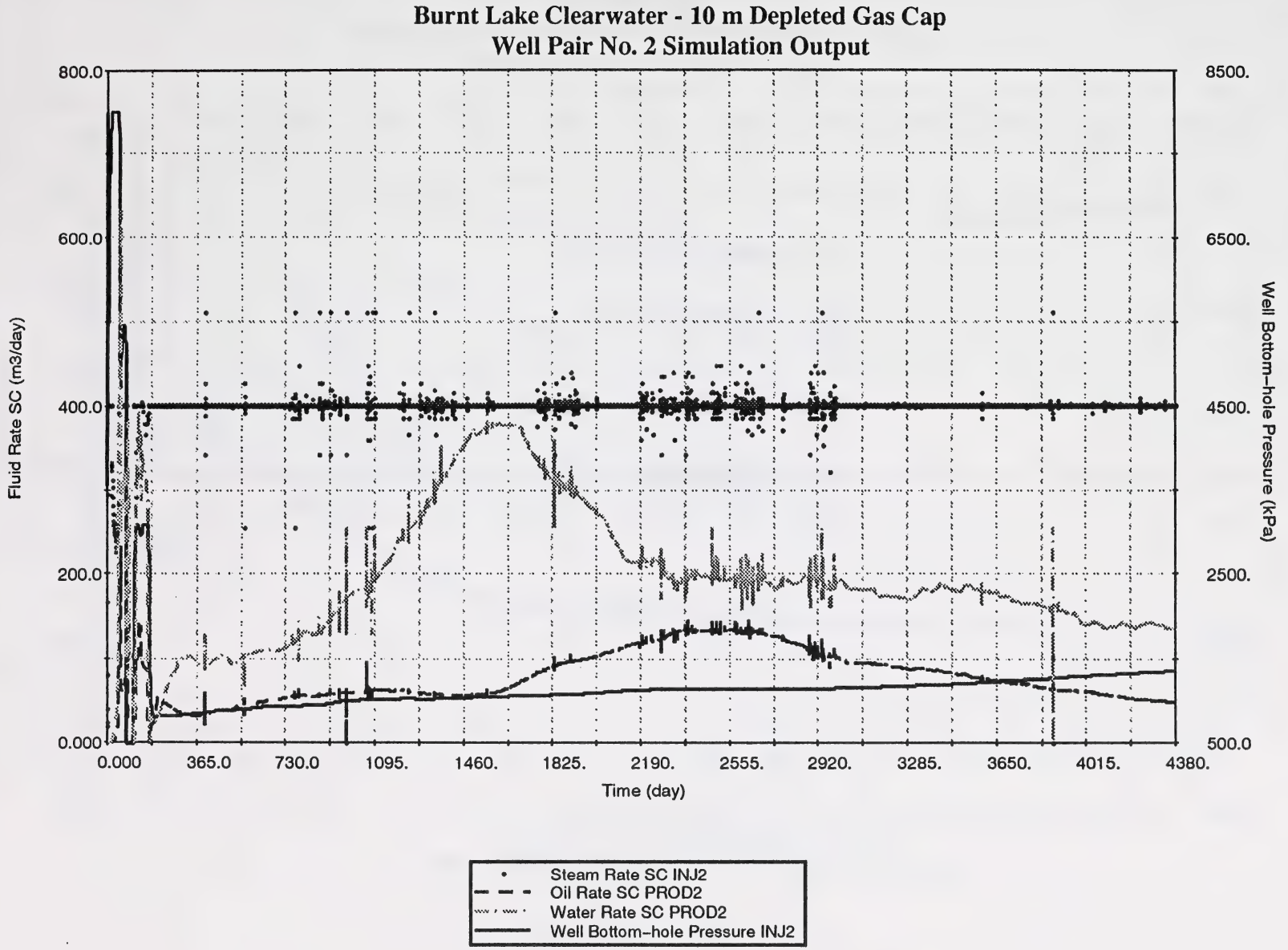

Burnt Lake Clearwater - 5 m Depleted Gas Cap
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8500.
6500.
4500.
2500.
500.0
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
Time (day)
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3

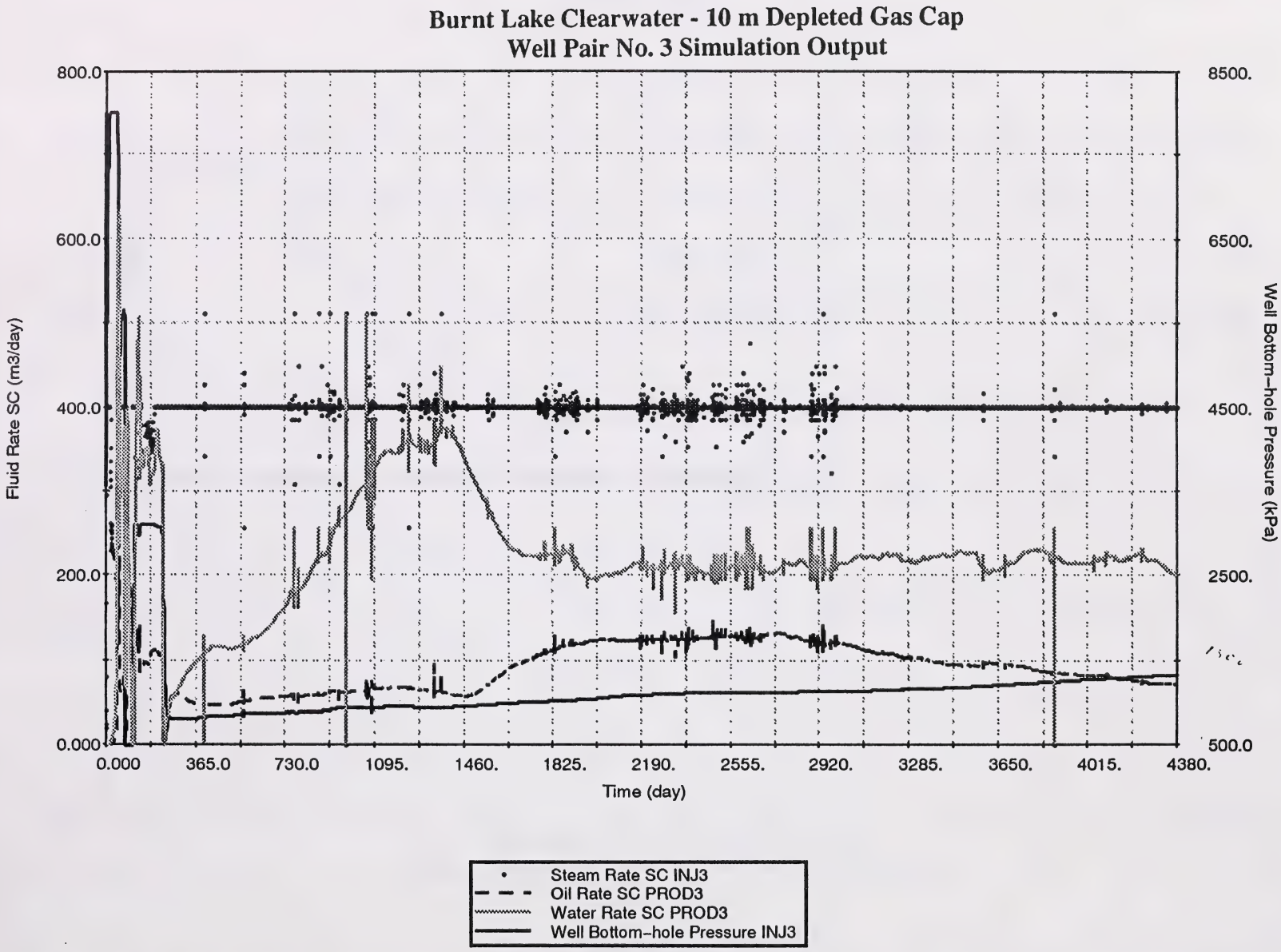

Burnt Lake Clearwater - 5 m Non-depleted Gas Cap
Well Pair No. 1 Simulation Output
Rate SC (m3/day)
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
8000.
7000.
6000.
5000.
4000.
3000.
2000.
1000.
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Steam Rate SC Inj 1
Oil Rate SC Prod 1
Water Rate SC Prod 1
Well Bottom-hole Pressure Inj 1

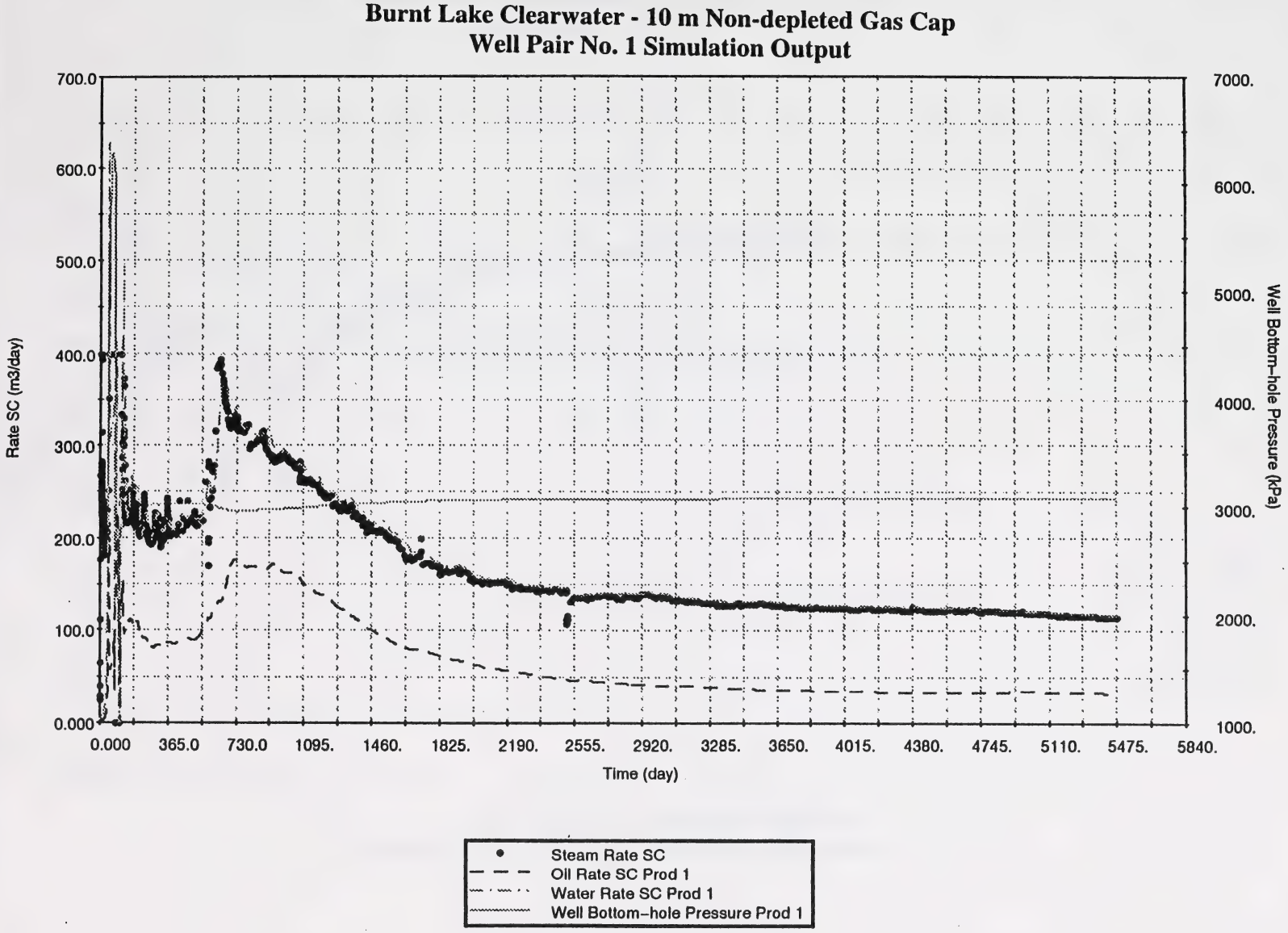

Burnt Lake Clearwater - 5 m Non-depleted Gas Cap
Well Pair No. 2 Simulation Output
Rate SC (m3/day)
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
8000.
7000.
6000.
5000.
4000.
3000.
2000.
1000.
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Steam Rate SC Inj 2
Oil Rate SC Prod 2
Water Rate SC Prod 2
Well Bottom-hole Pressure Inj 2

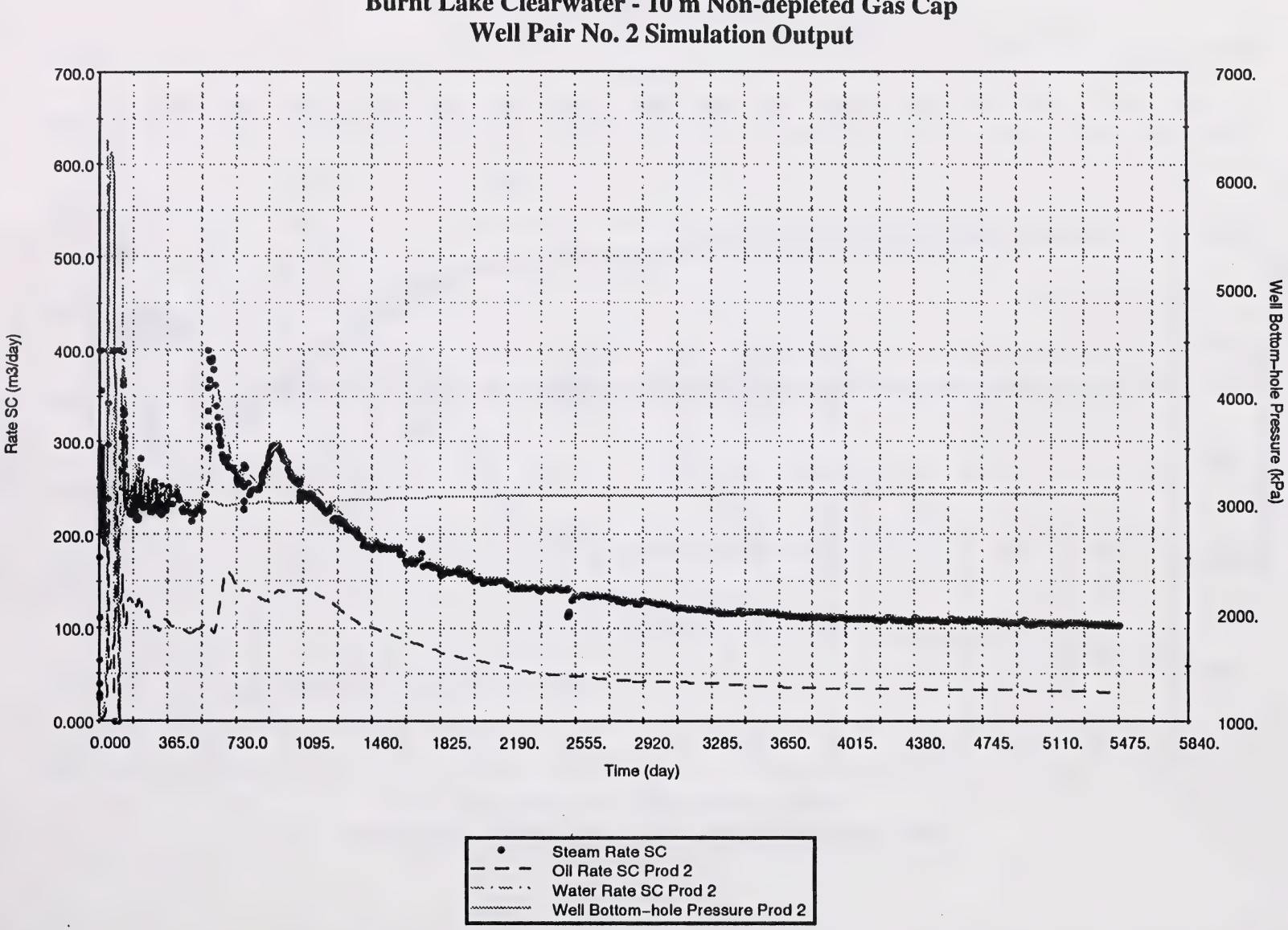

Burnt Lake Clearwater - 5 m Non-depleted Gas Cap
Well Pair No. 3 Simulation Output
Rate SC (m3/day)
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
8000.
7000.
6000.
5000.
4000.
3000.
2000.
1000.
0.000
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Steam Rate SC Inj 3
Oil Rate SC Prod 3
Water Rate SC Prod 3
Well Bottom-hole Pressure Inj 3

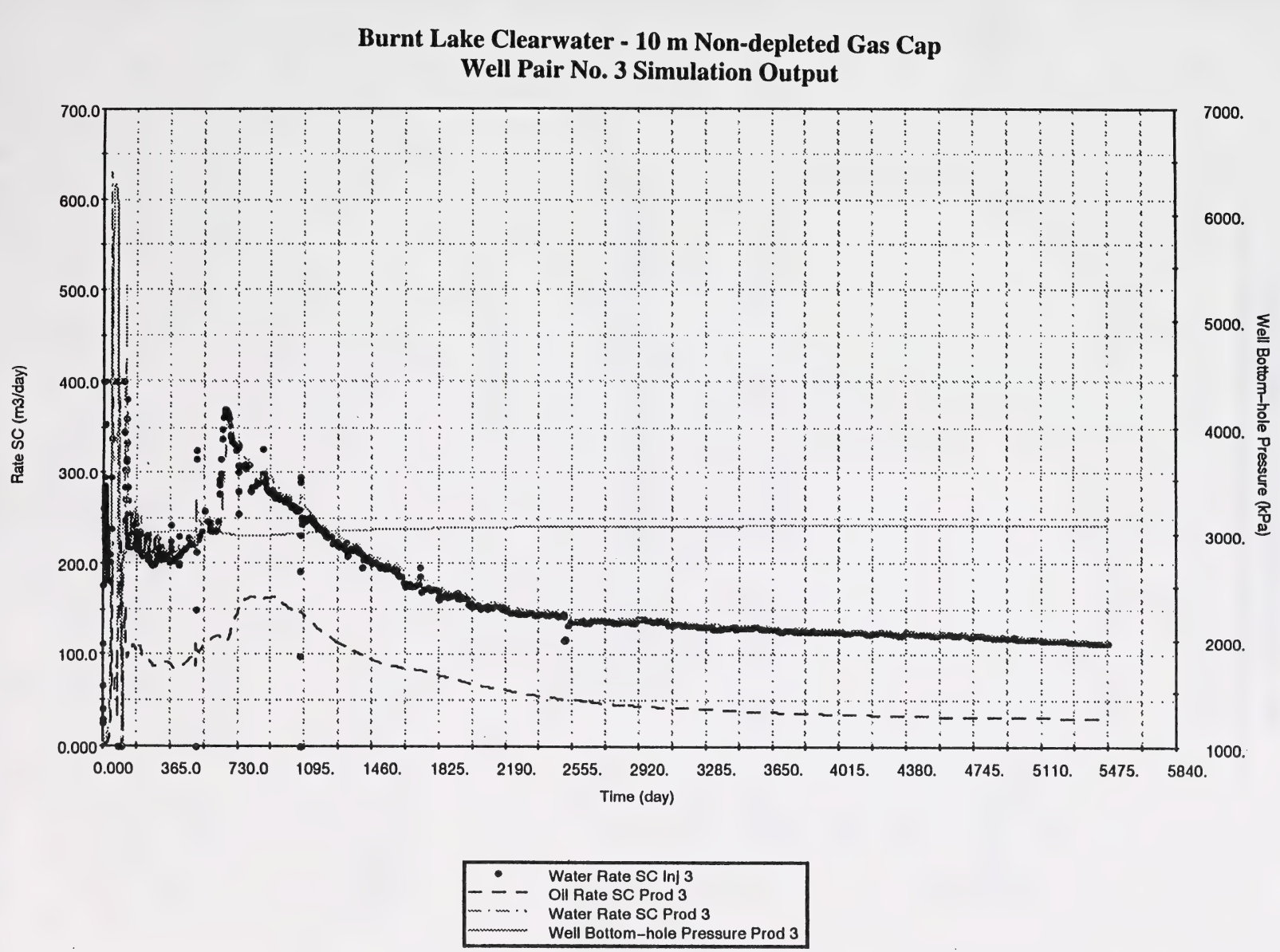

Burnt Lake Clearwater - 10 m Depleted Gas Cap
Well Pair No. 1 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8500.
6500.
4500.
2500.
500.0
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
Time (day)
Steam Rate SC INJ1
Oil Rate SC PROD1
Water Rate SC PROD1
Well Bottom-hole Pressure INJ1


Burnt Lake Clearwater - 10 m Depleted Gas Cap
Well Pair No. 2 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
Well Bottom-hole Pressure (kPa)
8500.
6500.
4500.
2500.
500.0
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
Time (day)
Steam Rate SC INJ2
Oil Rate SC PROD2
Water Rate SC PROD2
Well Bottom-hole Pressure INJ2

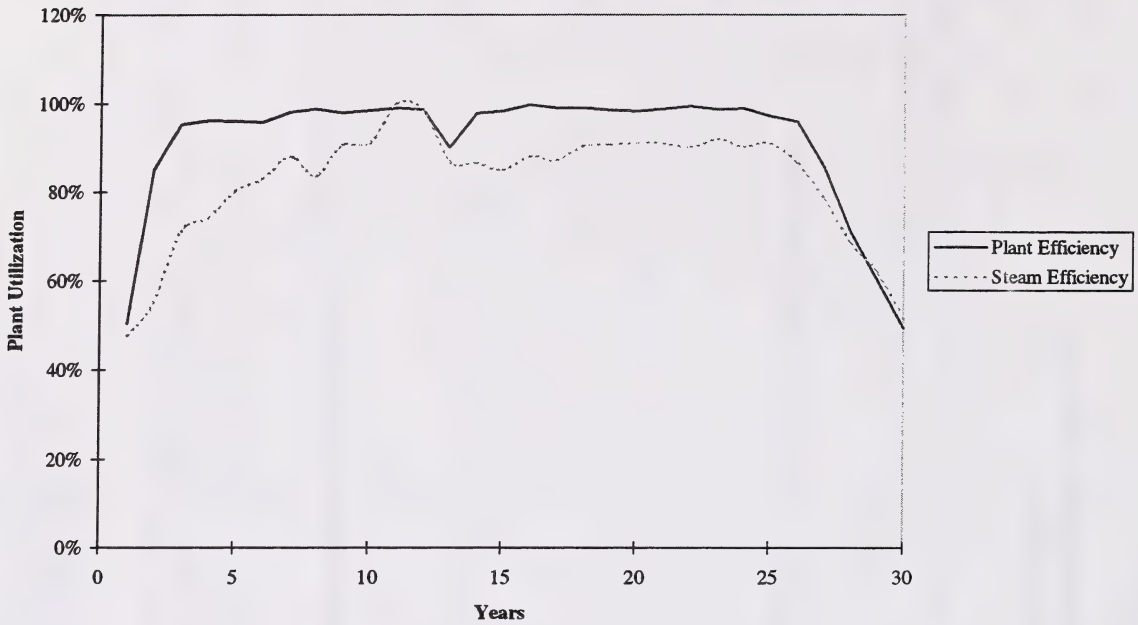

Burnt Lake Clearwater - 10 m Depleted Gas Cap
Well Pair No. 3 Simulation Output
Fluid Rate SC (m3/day)
800.0
600.0
400.0
200.0
0.000
8500.
6500.
4500.
2500.
500.0
Well Bottom-hole Pressure (kPa)
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
Time (day)
Steam Rate SC INJ3
Oil Rate SC PROD3
Water Rate SC PROD3
Well Bottom-hole Pressure INJ3


Burnt Lake Clearwater - 10 m Non-depleted Gas Cap
Well Pair No. 1 Simulation Output
Rate SC (m3/day)
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
7000.
6000.
5000.
4000.
3000.
2000.
1000.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Steam Rate SC
Oil Rate SC Prod 1
Water Rate SC Prod 1
Well Bottom-hole Pressure Prod 1

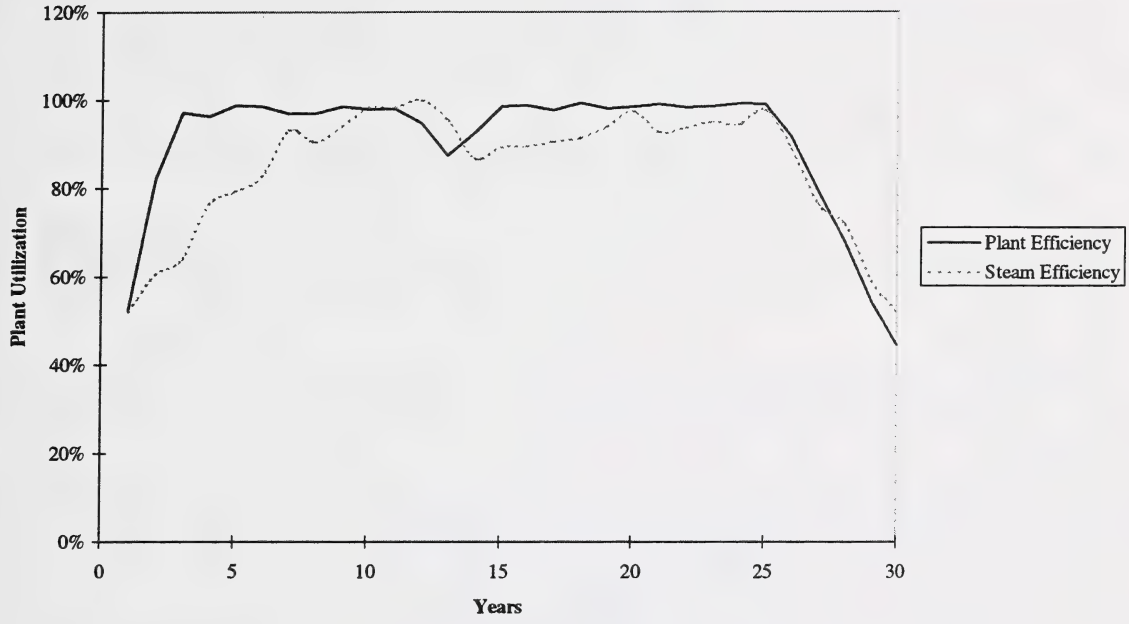

Burnt Lake Clearwater - 10 m Non-depleted Gas Cap
Well Pair No. 2 Simulation Output
Rate SC (m3/day)
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
Well Bottom-hole Pressure (kPa)
7000.
6000.
5000.
4000.
3000.
2000.
1000.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Time (day)
Steam Rate SC
Oil Rate SC Prod 2
Water Rate SC Prod 2
Well Bottom-hole Pressure Prod 2


Burnt Lake Clearwater - 10 m Non-depleted Gas Cap
Well Pair No. 3 Simulation Output
Rate SC (m3/day)
Well Bottom-hole Pressure (kPa)
Time (day)
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.000
7000.
6000.
5000.
4000.
3000.
2000.
1000.
0.000
365.0
730.0
1095.
1460.
1825.
2190.
2555.
2920.
3285.
3650.
4015.
4380.
4745.
5110.
5475.
5840.
Water Rate SC Inj 3
Oil Rate SC Prod 3
Water Rate SC Prod 3
Well Bottom-hole Pressure Prod 3

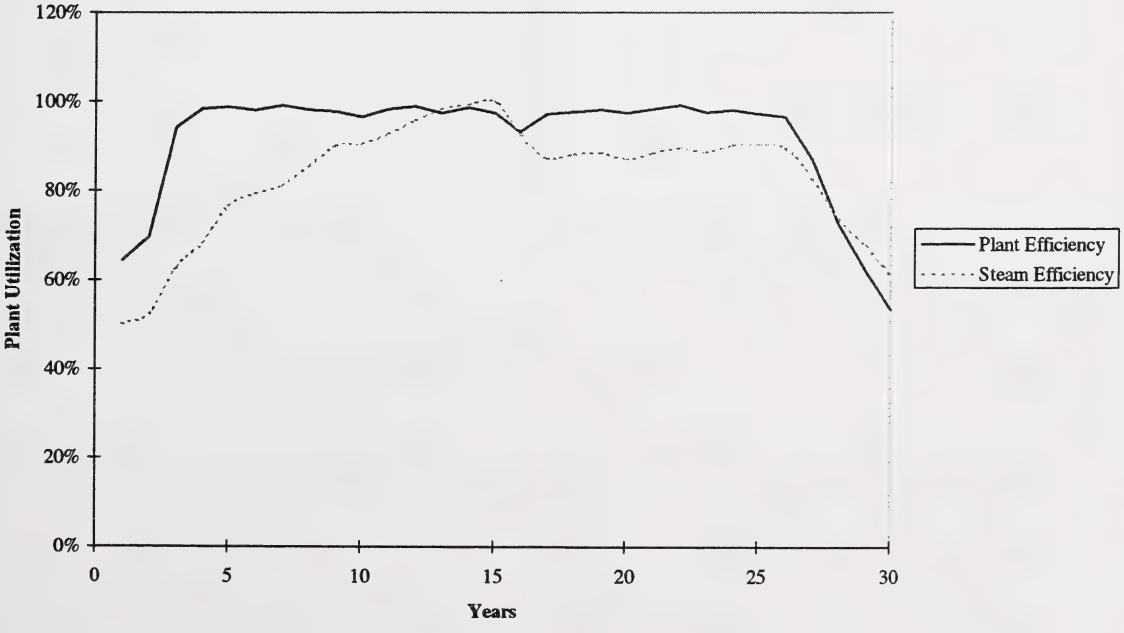
Plant Utilization of Bitumen and Steam Capacity
Burnt Lake Clearwater - 0 m Depleted Gas Cap (Live Oil)



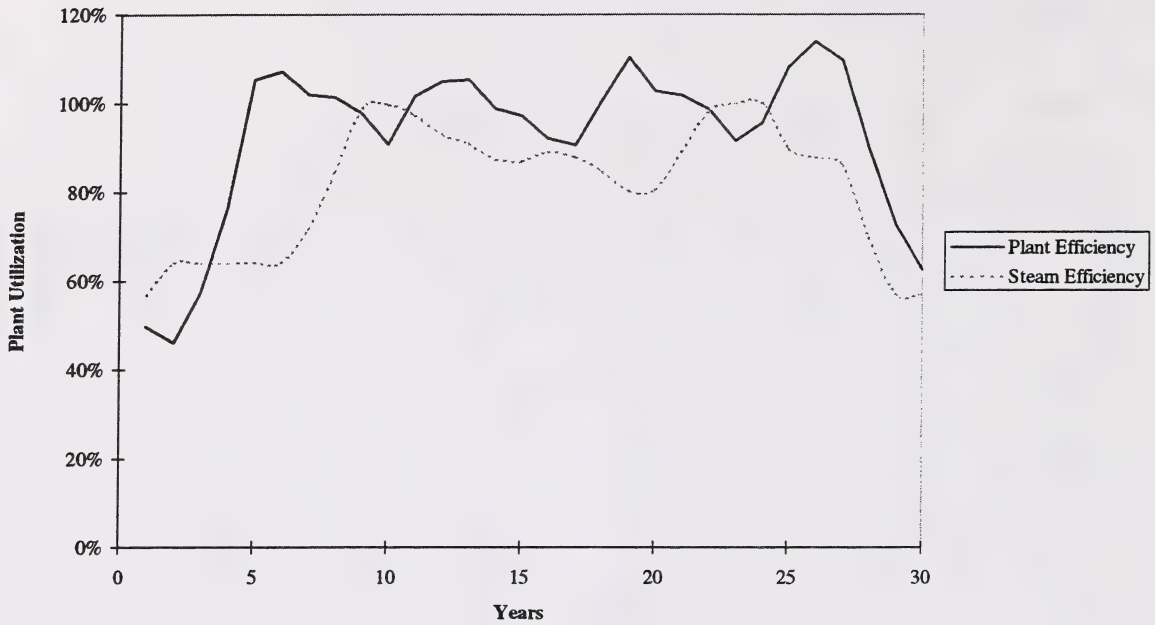
Plant Utilization of Bitumen and Steam Capacity
Burnt Lake Clearwater Case - 0 m Depleted Gas Cap



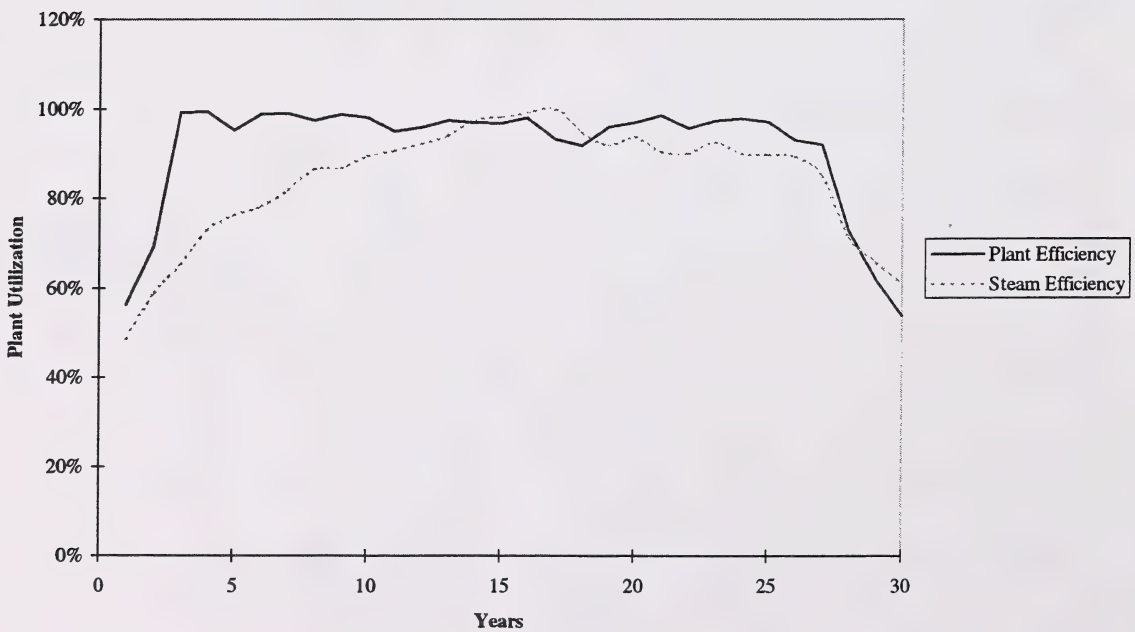
Plant Utilization of Bitumen and Steam Capacity
Burnt Lake Clearwater - 0 m Non-depleted Gas Cap



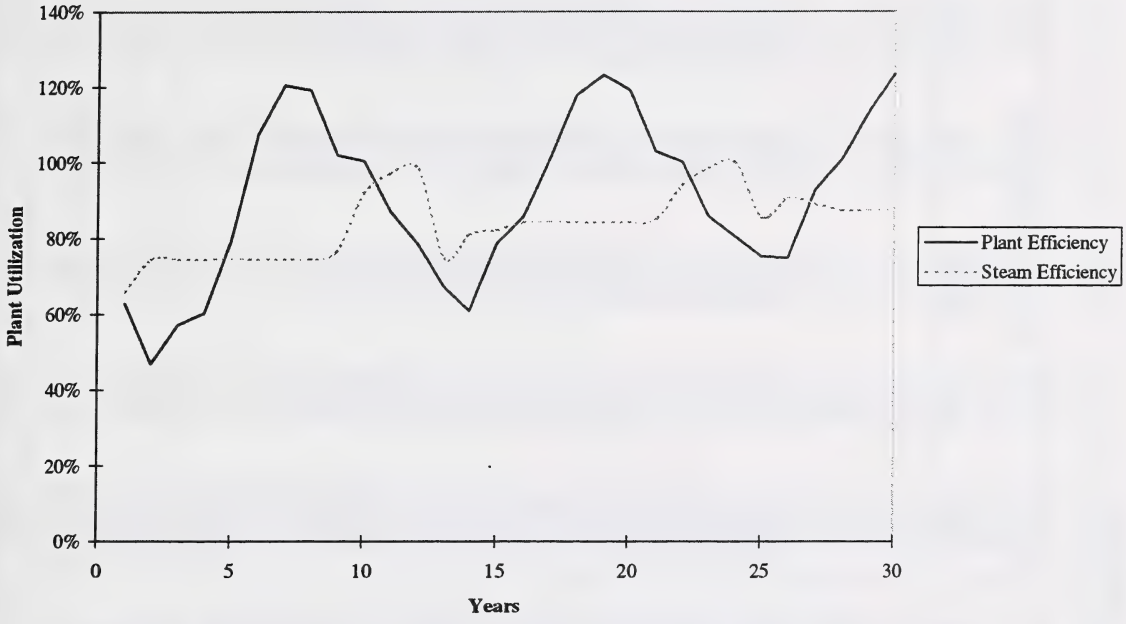
Plant Utilization of Bitumen and Steam Capacity
Burnt Lake Clearwater - 5 m Depleted Gas Cap



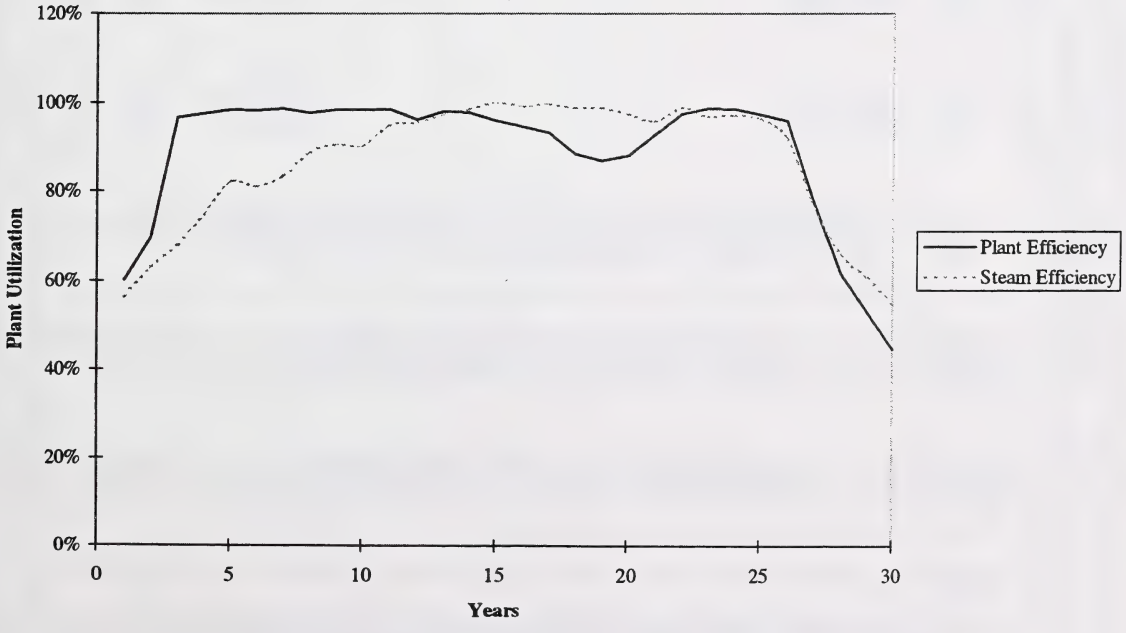
Plant Utilization of Bitumen and Steam Capacity
Burnt Lake Clearwater - 5 m Non-depleted Gas Cap



Plant Utilization of Bitumen and Steam Capacity
Burnt Lake Clearwater - 10 m Depleted Gas Cap



Plant Utilization of Bitumen and Steam Capacity
Burnt Lake Clearwater - 10 m Non-depleted Gas Cap



Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Burnt Lake Clearwater - 0 m Depleted Gas Cap (Live Oil)

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$105	$235	$340						
1997	8			$15,200	$143	$319	$15,661						
1998	8			$15,200	$34,936	$78,072	$128,207						
1999	8			$15,200	$35,835	$80,082	$131,117						
2000	9	2,402	8,491	$17,100	$9,528	$21,293	$47,922	$17,373	$4,680	$770	$1,209	$10,850	$34,883
2001	9	4,057	9,777	$17,100			$17,100	$20,004	$5,389	$1,167	$1,658	$10,850	$39,067
2002	9	4,546	12,626	$17,100			$17,100	$25,833	$6,959	$1,284	$2,055	$10,850	$46,981
2003	9	4,584	13,183	$17,100			$17,100	$26,972	$7,266	$1,293	$2,205	$10,850	$48,586
2004	9	4,580	14,282	$17,100			$17,100	$29,220	$7,872	$1,292	$2,362	$10,850	$51,596
2005	9	4,569	14,746	$17,100			$17,100	$30,170	$8,127	$1,290	$2,455	$10,850	$52,892
2006	9	4,677	15,648	$17,100			$17,100	$32,014	$8,624	$1,315	$2,607	$10,850	$55,411
2007	9	4,711	14,857	$17,100			$17,100	$30,396	$8,188	$1,324	$2,488	$10,850	$53,246
2008	9	4,670	16,094	$17,100			$17,100	$32,926	$8,870	$1,314	$2,662	$10,850	$56,622
2009	7	4,693	16,203	$13,300			$13,300	$33,150	$8,930	$1,319	$2,718	$10,850	$56,968
2010	0	4,726	17,786	$0			$0	$36,390	$9,803	$1,327	$2,956	$10,850	$61,326
2011	0	4,706	17,511	$0			$0	$35,826	$9,651	$1,322	$2,939	$10,850	$60,589
2012	0	4,297	15,447	$0			$0	$31,603	$8,514	$1,224	$2,532	$10,850	$54,724
2013	0	4,662	15,405	$0			$0	$31,518	$8,490	$1,312	$2,569	$10,850	$54,739
2014	0	4,684	15,094	$0			$0	$30,882	$8,319	$1,317	$2,499	$10,850	$53,867
2015	0	4,758	15,646	$0			$0	$32,010	$8,623	$1,335	$2,606	$10,850	$55,425
2016	0	4,726	15,488	$0			$0	$31,687	$8,536	$1,327	$2,576	$10,850	$54,976
2017	0	4,719	16,073	$0			$0	$32,885	$8,859	$1,325	$2,670	$10,850	$56,589
2018	0	4,700	16,136	$0			$0	$33,014	$8,894	$1,321	$2,694	$10,850	$56,773
2019	0	4,686	16,195	$0			$0	$33,134	$8,926	$1,317	$2,697	$10,850	$56,925
2020	0	4,713	16,204	$0			$0	$33,153	$8,931	$1,324	$2,685	$10,850	$56,943
2021	0	4,741	16,013	$0			$0	$32,761	$8,825	$1,331	$2,685	$10,850	$56,451
2022	0	4,707	16,341	$0			$0	$33,432	$9,006	$1,323	$2,694	$10,850	$57,304
2023	0	4,714	16,049	$0			$0	$32,836	$8,846	$1,324	$2,708	$10,850	$56,564
2024	0	4,632	16,201	$0			$0	$33,147	$8,929	$1,305	$2,658	$10,850	$56,888
2025	0	4,575	15,382	$0			$0	$31,471	$8,478	$1,291	$2,590	$10,850	$54,680
2026	0	4,083	13,943	$0			$0	$28,526	$7,685	$1,173	$2,349	$10,850	$50,583
2027	0	3,382	12,183	$0			$0	$24,926	$6,715	$1,005	$2,053	$10,850	$45,549
2028	0	2,861	10,969	$0			$0	$22,443	$6,046	$880	$1,847	$10,850	$42,065
2029	0	2,356	9,157	$0			$0	$18,734	$5,047	$760	$1,548	$16,450	$42,539
Totals	112	47,784,401	160,283,282	$212,800	$80,547	$180,000	$473,347	$898,436	$242,028	$37,213	$72,972	$331,100	$1,581,749

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Burnt Lake Clearwater Case - 0 m Depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$104	$235	$338						
1997	9			$17,100	$141	$319	$17,559						
1998	9			$17,100	$34,478	$78,072	$129,649						
1999	8			$15,200	$35,365	$80,082	$130,647						
2000	9	2,501	9,120	$17,100	$9,403	$21,293	$47,797	$18,660	$5,027	$794	$1,294	$10,850	$36,625
2001	9	3,913	10,609	$17,100			$17,100	$21,706	$5,847	$1,133	$1,758	$10,850	$41,294
2002	9	4,635	11,223	$17,100			$17,100	$22,961	$6,186	$1,305	$1,884	$10,850	$43,186
2003	9	4,591	13,410	$17,100			$17,100	$27,437	$7,391	$1,295	$2,185	$10,850	$49,158
2004	9	4,710	13,905	$17,100			$17,100	$28,448	$7,664	$1,323	$2,317	$10,850	$50,603
2005	9	4,700	14,487	$17,100			$17,100	$29,639	$7,985	$1,321	$2,381	$10,850	$52,176
2006	9	4,620	16,342	$17,100			$17,100	$33,435	$9,007	$1,302	$2,692	$10,850	$57,285
2007	9	4,622	15,871	$17,100			$17,100	$32,471	$8,747	$1,302	$2,704	$10,850	$56,075
2008	9	4,696	16,491	$17,100			$17,100	$33,740	$9,089	$1,320	$2,719	$10,850	$57,718
2009	1	4,667	17,235	$1,900			$1,900	$35,262	$9,499	$1,313	$2,879	$10,850	$59,803
2010	0	4,675	17,240	$0			$0	$35,271	$9,502	$1,315	$2,885	$10,850	$59,823
2011	0	4,516	17,553	$0			$0	$35,913	$9,674	$1,277	$2,940	$10,850	$60,654
2012	0	4,170	16,726	$0			$0	$34,221	$9,219	$1,194	$2,731	$10,850	$58,214
2013	0	4,416	15,215	$0			$0	$31,128	$8,386	$1,253	$2,495	$10,850	$54,111
2014	0	4,698	15,659	$0			$0	$32,037	$8,630	$1,320	$2,635	$10,850	$55,473
2015	0	4,710	15,689	$0			$0	$32,099	$8,647	$1,323	$2,596	$10,850	$55,515
2016	0	4,661	15,876	$0			$0	$32,481	$8,750	$1,312	$2,623	$10,850	$56,016
2017	0	4,732	16,037	$0			$0	$32,812	$8,839	$1,329	$2,697	$10,850	$56,526
2018	0	4,675	16,479	$0			$0	$33,714	$9,082	$1,315	$2,705	$10,850	$57,666
2019	0	4,693	17,096	$0			$0	$34,977	$9,422	$1,319	$2,834	$10,850	$59,402
2020	0	4,719	16,263	$0			$0	$33,273	$8,963	$1,326	$2,727	$10,850	$57,139
2021	0	4,685	16,437	$0			$0	$33,629	$9,059	$1,317	$2,715	$10,850	$57,570
2022	0	4,700	16,662	$0			$0	$34,089	$9,183	$1,321	$2,775	$10,850	$58,218
2023	0	4,729	16,555	$0			$0	$33,871	$9,124	$1,328	$2,750	$10,850	$57,923
2024	0	4,724	17,145	$0			$0	$35,078	$9,450	$1,327	$2,852	$10,850	$59,557
2025	0	4,378	15,606	$0			$0	$31,928	$8,601	$1,244	$2,618	$10,850	$55,241
2026	0	3,788	13,418	$0			$0	$27,452	$7,395	$1,103	$2,260	$10,850	$49,060
2027	0	3,234	12,593	$0			$0	$25,764	$6,940	$970	$2,117	$10,850	$46,641
2028	0	2,584	10,333	$0			$0	$21,141	$5,695	$814	$1,745	$10,850	$40,246
2029	0	2,118	9,088	$0			$0	$18,594	$5,009	$702	$1,531	$16,250	$42,086
Totals	108	47,181,571	162,922,549	$205,200	$79,491	$180,000	$464,691	$913,230	$246,013	$36,817	$74,042	$330,900	$1,601,003

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Burnt Lake Clearwater - 0 m Non-depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$89	$235	$324						
1997	11			$14,850	$121	$319	$15,290						
1998	11			$14,850	$29,661	$78,072	$122,583						
1999	10			$13,500	$30,425	$80,082	$124,006						
2000	9	3,078	7,589	$12,150	$8,090	$21,293	$41,533	$15,526	$4,182	$932	$1,240	$10,850	$32,731
2001	9	3,322	7,919	$12,150			$12,150	$16,202	$4,365	$991	$1,343	$10,850	$33,750
2002	9	4,492	9,488	$12,150			$12,150	$19,411	$5,229	$1,271	$1,596	$10,850	$38,357
2003	9	4,695	10,322	$12,150			$12,150	$21,118	$5,689	$1,320	$1,736	$10,850	$40,712
2004	9	4,712	11,577	$12,150			$12,150	$23,686	$6,381	$1,324	$1,959	$10,850	$44,200
2005	9	4,674	11,987	$12,150			$12,150	$24,524	$6,607	$1,315	$2,032	$10,850	$45,327
2006	9	4,729	12,254	$12,150			$12,150	$25,071	$6,754	$1,328	$2,066	$10,850	$46,068
2007	9	4,679	12,901	$12,150			$12,150	$26,395	$7,110	$1,316	$2,181	$10,850	$47,852
2008	9	4,665	13,628	$12,150			$12,150	$27,881	$7,511	$1,312	$2,311	$10,850	$49,866
2009	9	4,606	13,660	$12,150			$12,150	$27,947	$7,528	$1,298	$2,317	$10,850	$49,941
2010	0	4,686	14,010	$0			$0	$28,663	$7,722	$1,318	$2,366	$10,850	$50,919
2011	0	4,717	14,462	$0			$0	$29,588	$7,971	$1,325	$2,453	$10,850	$52,187
2012	0	4,651	14,840	$0			$0	$30,362	$8,179	$1,309	$2,518	$10,850	$53,218
2013	0	4,707	14,992	$0			$0	$30,672	$8,263	$1,323	$2,548	$10,850	$53,655
2014	0	4,643	15,101	$0			$0	$30,895	$8,323	$1,307	$2,574	$10,850	$53,950
2015	0	4,446	13,965	$0			$0	$28,572	$7,697	$1,260	$2,348	$10,850	$50,727
2016	0	4,638	13,187	$0			$0	$26,979	$7,268	$1,306	$2,250	$10,850	$48,653
2017	0	4,659	13,319	$0			$0	$27,249	$7,341	$1,311	$2,260	$10,850	$49,010
2018	0	4,678	13,365	$0			$0	$27,344	$7,366	$1,316	$2,259	$10,850	$49,135
2019	0	4,649	13,165	$0			$0	$26,935	$7,256	$1,309	$2,223	$10,850	$48,573
2020	0	4,688	13,353	$0			$0	$27,320	$7,360	$1,318	$2,273	$10,850	$49,121
2021	0	4,728	13,536	$0			$0	$27,694	$7,460	$1,328	$2,295	$10,850	$49,627
2022	0	4,655	13,386	$0			$0	$27,387	$7,378	$1,310	$2,259	$10,850	$49,184
2023	0	4,673	13,624	$0			$0	$27,873	$7,509	$1,314	$2,306	$10,850	$49,852
2024	0	4,634	13,645	$0			$0	$27,916	$7,520	$1,305	$2,324	$10,850	$49,916
2025	0	4,607	13,540	$0			$0	$27,701	$7,462	$1,299	$2,297	$10,850	$49,610
2026	0	4,151	12,482	$0			$0	$25,537	$6,879	$1,190	$2,122	$10,850	$46,578
2027	0	3,459	11,133	$0			$0	$22,777	$6,136	$1,024	$1,895	$10,850	$42,681
2028	0	2,964	10,224	$0			$0	$20,918	$5,635	$905	$1,741	$10,850	$40,049
2029	0	2,551	9,202	$0			$0	$18,826	$5,072	$806	$1,566	$16,950	$43,220
Totals	122	47,900,862	137,186,188	$164,700	$68,386	$180,000	$413,086	$768,970	$207,151	$37,289	$63,660	$331,600	$1,408,671

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Burnt Lake Clearwater - 5 m Depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$135	$235	$370						
1997	12			$16,200	$184	$319	$16,703						
1998	12			$16,200	$45,055	$78,072	$139,326						
1999	12			$16,200	$46,215	$80,082	$142,496						
2000	9	2,369	13,022	$12,150	$12,288	$21,293	$45,732	$26,642	$7,177	$763	$1,064	$10,850	$46,496
2001	9	2,199	14,694	$12,150			$12,150	$30,063	$8,099	$722	$1,059	$10,850	$50,792
2002	9	2,739	14,694	$12,150			$12,150	$30,063	$8,099	$851	$1,854	$10,850	$51,717
2003	9	3,645	14,694	$12,150			$12,150	$30,063	$8,099	$1,068	$2,034	$10,850	$52,113
2004	9	5,022	14,734	$12,150			$12,150	$30,145	$8,121	$1,398	$1,821	$10,850	$52,335
2005	9	5,109	14,694	$12,150			$12,150	$30,063	$8,099	$1,419	$1,902	$10,850	$52,332
2006	9	4,864	16,448	$12,150			$12,150	$33,651	$9,065	$1,360	$2,210	$10,850	$57,136
2007	9	4,833	19,372	$12,150			$12,150	$39,633	$10,677	$1,353	$2,566	$10,850	$65,078
2008	9	4,663	22,665	$12,150			$12,150	$46,371	$12,492	$1,312	$2,956	$10,850	$73,981
2009	1	4,332	22,857	$1,350			$1,350	$46,764	$12,598	$1,233	$3,195	$10,850	$74,640
2010	0	4,847	22,296	$0			$0	$45,616	$12,288	$1,356	$3,268	$10,850	$73,379
2011	0	5,003	21,325	$0			$0	$43,629	$11,753	$1,394	$2,917	$10,850	$70,543
2012	0	5,022	20,853	$0			$0	$42,664	$11,493	$1,398	$3,013	$10,850	$69,418
2013	0	4,712	20,041	$0			$0	$41,003	$11,046	$1,324	$2,862	$10,850	$67,085
2014	0	4,631	19,929	$0			$0	$40,774	$10,984	$1,305	$2,164	$10,850	$66,076
2015	0	4,392	20,417	$0			$0	$41,772	$11,253	$1,247	$2,433	$10,850	$67,555
2016	0	4,322	20,153	$0			$0	$41,232	$11,107	$1,230	$2,912	$10,850	$67,332
2017	0	4,806	19,432	$0			$0	$39,757	$10,710	$1,346	$2,803	$10,850	$65,467
2018	0	5,261	18,407	$0			$0	$37,660	$10,145	$1,455	$2,592	$10,850	$62,703
2019	0	4,898	18,450	$0			$0	$37,748	$10,169	$1,368	$2,634	$10,850	$62,769
2020	0	4,856	20,401	$0			$0	$41,740	$11,244	$1,358	$2,759	$10,850	$67,951
2021	0	4,705	22,511	$0			$0	$46,056	$12,407	$1,322	$2,724	$10,850	$73,359
2022	0	4,366	22,899	$0			$0	$46,849	$12,621	$1,241	$2,924	$10,850	$74,485
2023	0	4,555	22,938	$0			$0	$46,930	$12,642	$1,286	$3,228	$10,850	$74,936
2024	0	5,162	20,591	$0			$0	$42,127	$11,349	$1,432	$2,873	$10,850	$68,631
2025	0	5,433	20,127	$0			$0	$41,179	$11,093	$1,497	$2,724	$10,850	$67,343
2026	0	5,234	19,743	$0			$0	$40,394	$10,882	$1,449	$2,851	$10,850	$66,425
2027	0	4,288	16,010	$0			$0	$32,755	$8,824	$1,222	$2,331	$10,850	$55,982
2028	0	3,475	13,070	$0			$0	$26,741	$7,204	$1,028	$1,934	$10,850	$47,756
2029	0	2,986	13,035	$0			$0	$26,669	$7,184	$910	$1,988	$16,750	$53,502
Totals	118	48,447,098	204,583,395	$159,300	$103,877	$180,000	$443,177	$1,146,751	$308,921	$37,648	$74,596	$331,400	$1,899,317

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Burnt Lake Clearwater - 5 m Non-depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$82	$235	$317						
1997	10			$13,500	$112	$319	$13,931						
1998	10			$13,500	$27,432	$78,072	$119,003						
1999	8			$10,800	$28,138	$80,082	$119,019						
2000	9	2,681	6,791	$12,150	$7,482	$21,293	$40,925	$13,894	$3,743	$837	$1,081	$10,850	$30,405
2001	9	3,293	8,211	$12,150			$12,150	$16,799	$4,525	$984	$1,361	$10,850	$34,519
2002	9	4,732	9,125	$12,150			$12,150	$18,669	$5,029	$1,329	$1,558	$10,850	$37,435
2003	9	4,736	10,173	$12,150			$12,150	$20,813	$5,607	$1,329	$1,719	$10,850	$40,318
2004	9	4,543	10,636	$12,150			$12,150	$21,760	$5,862	$1,283	$1,811	$10,850	$41,565
2005	9	4,717	10,918	$12,150			$12,150	$22,337	$6,017	$1,325	$1,855	$10,850	$42,384
2006	9	4,724	11,429	$12,150			$12,150	$23,382	$6,299	$1,327	$1,942	$10,850	$43,800
2007	9	4,647	12,071	$12,150			$12,150	$24,696	$6,653	$1,308	$2,054	$10,850	$45,561
2008	9	4,710	12,116	$12,150			$12,150	$24,788	$6,678	$1,323	$2,072	$10,850	$45,711
2009	9	4,679	12,474	$12,150			$12,150	$25,522	$6,875	$1,316	$2,109	$10,850	$46,672
2010	9	4,526	12,639	$12,150			$12,150	$25,859	$6,966	$1,279	$2,162	$10,850	$47,116
2011	1	4,568	12,865	$1,350			$1,350	$26,321	$7,091	$1,289	$2,188	$10,850	$47,739
2012	0	4,646	13,121	$0			$0	$26,845	$7,232	$1,308	$2,234	$10,850	$48,469
2013	0	4,618	13,602	$0			$0	$27,828	$7,497	$1,301	$2,321	$10,850	$49,797
2014	0	4,618	13,702	$0			$0	$28,034	$7,552	$1,301	$2,335	$10,850	$50,072
2015	0	4,679	13,852	$0			$0	$28,340	$7,634	$1,316	$2,370	$10,850	$50,509
2016	0	4,444	13,966	$0			$0	$28,573	$7,697	$1,260	$2,385	$10,850	$50,765
2017	0	4,372	13,238	$0			$0	$27,085	$7,296	$1,242	$2,231	$10,850	$48,705
2018	0	4,577	12,818	$0			$0	$26,224	$7,064	$1,291	$2,191	$10,850	$47,621
2019	0	4,624	13,077	$0			$0	$26,755	$7,208	$1,303	$2,229	$10,850	$48,345
2020	0	4,698	12,623	$0			$0	$25,826	$6,957	$1,320	$2,147	$10,850	$47,100
2021	0	4,555	12,564	$0			$0	$25,705	$6,925	$1,286	$2,131	$10,850	$46,896
2022	0	4,641	12,921	$0			$0	$26,435	$7,121	$1,307	$2,204	$10,850	$47,917
2023	0	4,662	12,552	$0			$0	$25,681	$6,918	$1,312	$2,134	$10,850	$46,895
2024	0	4,629	12,531	$0			$0	$25,639	$6,907	$1,304	$2,134	$10,850	$46,833
2025	0	4,434	12,470	$0			$0	$25,513	$6,873	$1,257	$2,124	$10,850	$46,617
2026	0	4,388	11,869	$0			$0	$24,284	$6,542	$1,246	$2,038	$10,850	$44,960
2027	0	3,474	9,952	$0			$0	$20,361	$5,485	$1,027	$1,710	$10,850	$39,433
2028	0	2,946	9,202	$0			$0	$18,827	$5,072	$901	$1,577	$10,850	$37,227
2029	0	2,570	8,526	$0			$0	$17,445	$4,699	$811	$1,460	$17,250	$41,665
Totals	128	47,497,474	128,492,287	$172,800	$63,245	$180,000	$416,045	$720,238	$194,023	$37,025	$59,864	$331,900	$1,343,050

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Burnt Lake Clearwater - 10 m Depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$149	$235	$384						
1997	16			$21,600	$202	$319	$22,121						
1998	16			$21,600	$49,523	$78,072	$149,194						
1999	14			$18,900	$50,798	$80,082	$149,779						
2000	9	3,003	16,627	$12,150	$13,507	$21,293	$46,950	$34,018	$9,164	$914	$1,357	$10,850	$56,304
2001	9	2,240	18,776	$12,150			$12,150	$38,413	$10,348	$732	$949	$10,850	$61,292
2002	9	2,731	18,776	$12,150			$12,150	$38,413	$10,348	$849	$1,706	$10,850	$62,167
2003	9	2,875	18,776	$12,150			$12,150	$38,413	$10,348	$884	$2,669	$10,850	$63,165
2004	9	3,778	18,827	$12,150			$12,150	$38,519	$10,376	$1,100	$2,310	$10,850	$63,155
2005	9	5,129	18,776	$12,150			$12,150	$38,413	$10,348	$1,424	$1,861	$10,850	$62,896
2006	9	5,749	18,775	$12,150			$12,150	$38,412	$10,348	$1,572	$1,635	$10,850	$62,817
2007	9	5,684	18,776	$12,150			$12,150	$38,413	$10,348	$1,557	$1,586	$10,850	$62,755
2008	9	4,866	19,293	$12,150			$12,150	$39,473	$10,634	$1,361	$1,589	$10,850	$63,907
2009	9	4,792	23,156	$12,150			$12,150	$47,375	$12,762	$1,343	$1,898	$10,850	$74,228
2010	9	4,157	24,487	$12,150			$12,150	$50,098	$13,496	$1,191	$1,773	$10,850	$77,408
2011	7	3,744	24,803	$9,450			$9,450	$50,745	$13,670	$1,092	$1,911	$10,850	$78,268
2012	0	3,207	18,823	$0			$0	$38,511	$10,374	$963	$1,822	$10,850	$62,520
2013	0	2,906	20,419	$0			$0	$41,777	$11,254	$891	$1,470	$10,850	$66,242
2014	0	3,754	20,721	$0			$0	$42,394	$11,420	$1,094	$1,968	$10,850	$67,727
2015	0	4,095	21,225	$0			$0	$43,425	$11,698	$1,176	$2,632	$10,850	$69,781
2016	0	4,821	21,267	$0			$0	$43,511	$11,721	$1,350	$2,332	$10,850	$69,764
2017	0	5,622	21,236	$0			$0	$43,447	$11,704	$1,542	$2,019	$10,850	$69,561
2018	0	5,873	21,226	$0			$0	$43,428	$11,699	$1,602	$1,864	$10,850	$69,442
2019	0	5,684	21,227	$0			$0	$43,428	$11,699	$1,557	$1,778	$10,850	$69,312
2020	0	4,915	21,436	$0			$0	$43,856	$11,814	$1,373	$1,740	$10,850	$69,634
2021	0	4,773	23,697	$0			$0	$48,482	$13,061	$1,338	$1,905	$10,850	$75,636
2022	0	4,096	24,802	$0			$0	$50,743	$13,670	$1,176	$1,733	$10,850	$78,172
2023	0	3,836	25,213	$0			$0	$51,584	$13,896	$1,114	$2,014	$10,850	$79,458
2024	0	3,594	21,555	$0			$0	$44,099	$11,880	$1,056	$2,228	$10,850	$70,113
2025	0	3,569	22,875	$0			$0	$46,801	$12,608	$1,050	$1,896	$10,850	$73,204
2026	0	4,424	22,455	$0			$0	$45,941	$12,376	$1,255	$2,172	$10,850	$72,593
2027	0	4,821	22,043	$0			$0	$45,098	$12,149	$1,350	$2,614	$10,850	$72,061
2028	0	5,426	22,079	$0			$0	$45,172	$12,169	$1,495	$2,327	$10,850	$72,013
2029	0	5,895	22,059	$0			$0	$45,131	$12,158	$1,607	$2,015	$18,450	$79,360
Totals	152	47,472,032	231,483,478	$205,200	$114,178	$180,000	$499,378	$1,297,535	$349,540	$37,008	$57,774	$333,100	$2,074,957

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Burnt Lake Clearwater - 10 m Non-depleted Gas Cap

Year	Well Pairs Drilled	Bitumen Prod. (m3/d)	Steam Injection (m3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$76	$235	$311						
1997	10			$13,500	$103	$319	$13,922						
1998	10			$13,500	$25,350	$78,072	$116,922						
1999	10			$13,500	$26,003	$80,082	$119,584						
2000	9	2,870	7,264	$12,150	$6,914	$21,293	$40,357	$14,862	$4,004	$883	$1,157	$10,850	$31,754
2001	9	3,319	8,123	$12,150			$12,150	$16,620	$4,477	$990	$1,358	$10,850	$34,295
2002	9	4,612	8,753	$12,150			$12,150	$17,907	$4,824	$1,300	$1,503	$10,850	$36,384
2003	9	4,649	9,661	$12,150			$12,150	$19,766	$5,325	$1,309	$1,635	$10,850	$38,885
2004	9	4,689	10,600	$12,150			$12,150	$21,686	$5,842	$1,318	$1,817	$10,850	$41,513
2005	9	4,687	10,460	$12,150			$12,150	$21,400	$5,765	$1,318	$1,794	$10,850	$41,128
2006	9	4,706	10,770	$12,150			$12,150	$22,034	$5,936	$1,322	$1,835	$10,850	$41,977
2007	9	4,658	11,443	$12,150			$12,150	$23,411	$6,307	$1,311	$1,956	$10,850	$43,834
2008	9	4,695	11,700	$12,150			$12,150	$23,938	$6,449	$1,320	$2,011	$10,850	$44,567
2009	9	4,688	11,648	$12,150			$12,150	$23,830	$6,420	$1,318	$1,994	$10,850	$44,412
2010	9	4,699	12,248	$12,150			$12,150	$25,059	$6,751	$1,321	$2,090	$10,850	$46,071
2011	-1	4,586	12,332	($1,350)			($1,350)	$25,231	$6,797	$1,294	$2,124	$10,850	$46,295
2012	0	4,675	12,559	$0			$0	$25,695	$6,922	$1,315	$2,147	$10,850	$46,929
2013	0	4,665	12,698	$0			$0	$25,978	$6,998	$1,313	$2,175	$10,850	$47,314
2014	0	4,575	12,906	$0			$0	$26,405	$7,113	$1,291	$2,216	$10,850	$47,876
2015	0	4,510	12,789	$0			$0	$26,165	$7,048	$1,275	$2,190	$10,850	$47,528
2016	0	4,448	12,865	$0			$0	$26,320	$7,090	$1,261	$2,204	$10,850	$47,725
2017	0	4,220	12,745	$0			$0	$26,075	$7,024	$1,206	$2,188	$10,850	$47,343
2018	0	4,150	12,754	$0			$0	$26,093	$7,029	$1,189	$2,189	$10,850	$47,351
2019	0	4,200	12,569	$0			$0	$25,715	$6,927	$1,201	$2,123	$10,850	$46,817
2020	0	4,422	12,357	$0			$0	$25,282	$6,811	$1,254	$2,123	$10,850	$46,320
2021	0	4,645	12,749	$0			$0	$26,083	$7,026	$1,308	$2,181	$10,850	$47,447
2022	0	4,708	12,500	$0			$0	$25,574	$6,889	$1,323	$2,130	$10,850	$46,766
2023	0	4,696	12,536	$0			$0	$25,648	$6,909	$1,320	$2,140	$10,850	$46,868
2024	0	4,636	12,430	$0			$0	$25,431	$6,851	$1,306	$2,130	$10,850	$46,568
2025	0	4,573	11,842	$0			$0	$24,228	$6,527	$1,291	$2,041	$10,850	$44,937
2026	0	3,688	9,881	$0			$0	$20,217	$5,446	$1,079	$1,710	$10,850	$39,302
2027	0	2,936	8,498	$0			$0	$17,386	$4,683	$898	$1,469	$10,850	$35,286
2028	0	2,512	7,830	$0			$0	$16,020	$4,316	$797	$1,351	$10,850	$33,333
2029	0	2,126	7,043	$0			$0	$14,409	$3,882	$704	$1,214	$17,250	$37,459
Totals	128	46,443,540	122,111,125	$172,800	$58,446	$180,000	$411,246	$684,470	$184,388	$36,333	$57,195	$331,900	$1,294,285

National Library of Canada
Bibliothèque nationale du Canada
3 3286 51276 8249

For more information or additional copies of the report (at $50 each), contact:

Alberta Department of Energy
Calgary Information Centre
3rd Floor, Monenco Place
801 – 6th Avenue SW
Calgary, Alberta T2P 3W2
Telephone: (403) 297-3624
Fax: (403) 297-2576

Copies of the report (at $50 each) are also available from:

Alberta Department of Energy
Mineral Access, Geology and Mapping
4th Floor, North Petroleum Plaza
9945 – 108 Street
Edmonton, Alberta T5K 2G6
Telephone (403) 427-8975
Fax (403) 422-3044

ISBN 07732-0951-4

Price: $50